84-1176

No. 84-

IN THE

Supreme Court of the United States

October Term, 1984

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,
Appellant,

v.

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK, OCCIDENTAL CHEMICAL CORPORATION, and THE BROOKLYN UNION GAS COMPANY,
Appellees.

ON APPEAL FROM THE COURT OF APPEALS OF THE STATE OF NEW YORK

APPENDIX TO JURISDICTIONAL STATEMENT

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Appendix A—Opinion of the Court of Appeals of the State of New York, October 25, 1984

(This opinion is uncorrected and subject to revision before publication in the New York Reports.)

STATE OF NEW YORK

COURT OF APPEALS

3 No. 438

IN THE MATTER
OF

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,

Respondent,

v.

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,

Appellant,

OCCIDENTAL CHEMICAL CORPORATION,

Intervenor,

and

THE BROOKLYN UNION GAS COMPANY,

Intervenor-Respondent.

(438) Timothy P. Sheehan & David E. Blabey, Albany, for appellant.

Bernard L. Sanoff, Joy Tannian, Peter Garam, John D. McMahon, & Celeste H.Contrucci, NY City, for respondent.

Earle H. O'Donnell, Washington, & Michael Whiteman, Albany, for intervenor-respondent-appellant.

COOKE, Ch. J.:

The Public Utility Regulatory Policies Act of 1978 (PURPA) does not preempt this State from requiring electric utilities to offer to buy energy from those alternate energy producers, that qualify under both federal and state law, at a rate in excess of the maximum rate under PURPA. However, the State is preempted by provisions of the Federal Power Act (FPA) from requiring electric utilities to offer to purchase power from purely state qualifying alternate energy facilities.

Responding to the nationwide energy crisis, Congress enacted PURPA in 1978 for the purpose of encouraging the development of alternate energy sources, in order to reduce this country's dependence on traditional fossil fuels (see *FERC v Mississippi*, 456 US 742, 750). Accordingly, section 210 of PURPA (16 USC § 824a-3 [a]) mandates the Federal Energy Regulatory Commission (FERC) to prescribe rules that will foster development of qualifying cogeneration facilities and qualifying small power production facilities.[1] By further directing FERC to promulgate

[1]A "cogeneration facility" is one that produces both electric energy and steam or some other form of useful energy, such as heat (see 16 USC §796 [18] [A]).

A "small power production facility" is one that produces electric power from biomass, waste, renewable resources such as wind, water or solar energy, or geothermal resources and has a production capacity of not more than 80 megawatts (see 16 USC §796 [17] [A]).

Each cogeneration or small power production facility will be a "qualifying" one if it satisfies the requirements regarding ownership, size, fuel use, efficiency, and reliability under PURPA (see 16 USC §796 [17] [C], [18] [B]).

rules requiring electric utilities to offer to sell and purchase electric energy to and from such federal qualifying facilities, Congress hoped to eliminate one of the central problems that had hindered the development of alternate energy sources: traditional electric utilities were reluctant to buy power from, or sell power to the alternate power producers (see *FERC v Mississippi, supra*, at 750 & n. 12).

With respect to the regulatory rates established by FERC for purchases by electric utilities, PURPA directs that they be (1) just and reasonable to the electric consumers of the utility, (2) in the public interest, and (3) not discriminatory against qualifying cogenerators or small power producers (see 16 USC § 824a-3 [b]). PURPA further limits the purchase rate by providing that FERC may not establish a rate that exceeds the purchasing utility's "avoided cost"[2] (see *id.*).

A second barrier to alternate energy producers was the applicability of voluminous federal and state utility regulations, involving tremendous amounts of paperwork. To avoid financially and administratively overburdening qualifying facilities, section 210 of PURPA authorizes FERC to exempt many federal qualifying facilities from certain federal and state laws, including the Federal Power Act (FPA) (see 16 USC §824a-3 [e][1]; 18 CFR 292.601), when deemed necessary in order to encourage alternate power producers to enter the field (see *FERC v Mississippi*, 456 US 742,750-751, *supra*; 1978 US Code Cong. & Admin. News, p 7832).

[2]A utility's "avoided cost" is the amount that it would have cost the utility to generate the same energy that it bought from the qualifying cogeneration or small power production facility, had that purchase not been made (see 16 USC §824a-3 [d]). This is referred to in the statute as the utility's "incremental cost of alternate electric energy."

The purchase rate actually selected by FERC in its regulations is generally equal to avoided purchase costs and although it may be lower (see 18 CFR § 292.304[b][2]-[3]), FERC may not require it to be higher (see 18 CFR § 292.304[a][2]).

After the enactment of PURPA, New York State passed a similar law in 1980 (L 1980, ch 553, § 7, as amended L 1981, ch 843, § 9, cod at Public Service Law, § 66-c). Its purpose is to promote State energy goals of development of alternate energy production facilities, cogeneration facilities, and small hydro facilities (see Public Service Law, §66-c; State Energy Master Plan, Final Report, Vol. I, pp 5-10, 29-30[3/82]).To encourage this development, the law requires electric utilities to both sell and purchase power produced by state qualifying facilities (see Public Service Law, § 66-c[1]). Generally, those facilities that qualify under PURPA in this State also qualify under the state law (see Public Service Law, §§ 2-a, 2-b, 2-c).[3]

Like PURPA, section 66-c of the Public Service Law requires that the purchasing rates by a utility from a state qualifying facility be just, non-discriminatory, and in furtherance of the public policy behind the legislation.The state statute differs from PURPA, however, in that it prescribes a uniform minimum purchase price of 6 cents per kilowatt hour for electricity purchased by a utility from a state qualifying facility, rather than PURPA's variable avoided-cost purchase rate. This state's minimum purchase rate may at times exceed a utility's avoided cost, the maximum purchase rate for energy from a federal qualifying facility that can be required by FERC under PURPA (see 16 USC §824a-3[a]; 18 CFR 292.304 [a][2]).

After conducting hearings to implement the federal and state legislation and regulations, respondent Public Service Commission (PSC) determined, among other things,

[3]Unless otherwise indicated, when the term "federal qualifying facility" is used in this opinion, it will include facilities that are also state qualifying facilities. A "state qualifying facility" will refer to any facility qualifying under the Public Service Law, regardless of whether it is also a federal qualifying facility. Some facilities, however, will qualify under one law and not the other (compare 16 USC §796 [17], [18] & 18 CFR 292.201-206 with Public Service Law, §§ 2-a, 2-b, 2-c) and will be referred to as a "purely" state or "purely" federal qualifying facility.

that petitioner Consolidated Edison must offer to purchase electric energy from on-site generation facilities[4] that qualify under either federal or state law, or both. It also required petitioner, under state law, to offer to purchase at a rate of least 6 cents per kilowatt hour from state qualifying facilities and at a rate of at least avoided cost from any purely federal qualifying facility under PURPA.

On September 9, 1982, petitioner commenced this article 78 proceeding challenging, on federal preemption grounds, these two aspects of the PSC's determination.

The Appellate Division granted the petition, in part, holding that the FPA and PURPA preempted the area and, therefore, that FERC had exclusive jurisdiction to determine rates for sales of electricity at wholesale by on-site generators. The court modified the determination of the PSC by declaring that the State could only require petitioner to offer to purchase electricity from on-site generators that were federal qualifying facilities. The required purchase of electricity from purely state qualifying facilities, however, was deemed to be under the preemptive blanket of the FPA. Further, the state requirement of a 6 cents per kilowatt hour minimum purchase rate was held invalid to the extent it conflicted with the federally mandated maximum rate of avoided costs.

I

The first issue is whether PURPA preempts state regulation requiring electric utilities to purchase power from federal qualifying facilities at a rate in excess of the avoided cost purchase rate required under PURPA. This court holds that PURPA has no such effect.

Based upon the Supremacy Clause of the United States Constitution (see U.S. Const., Art VI, cl. 2), federal law will prohibit the enforcement of state regulation in several

[4]On-site generation facilities refer, in this opinion, to all alternate energy producers regardless of whether they qualify under federal and/or state law.

circumstances. Preemption[5] will arise if the federal statute contains express language indicating Congressional intent to preempt the field sought to be regulated by state law (see *Jones v Rath Packing Co.*, 430 US 519, 525). In the absence of express preemption, such may be implied from the comprehensive and pervasive nature of the federal legislation that indicates an intention by Congress to leave "no room for the States to supplement" federal law, or if the federal law concerns a dominant federal interest (see *Rice v Santa Fe Elevator Corp.*, 331 US 218, 230). Preemption may also be found when compliance with both federal and state law is an impossibility (see *Florida Lime & Avocado Growers, Inc. v Paul*, 373 US 132, 142-143). Indeed, if the state law "stands as an obstacle to the accomplishment and execution of the full purposes and objectives of Congress", as expressed in the conflicting federal statute, it must fall (*Hines v Davidowitz*, 312 US 52, 67; see also, *Capital Cities Cable, Inc. v Crisp*, ____ US ____, ____, 104 S Ct 2694, 2700).

Analysis under the Supremacy Clause, however, begins with the assumption that Congress did not intend to prohibit state action (see *Maryland v Louisiana*, 451 US 725, 746; *Chicago & North Western Transp. Co. v Kalo Brick & Tile Co.*, 450 US 311, 317). This is especially so when the federal enactment would displace a state statute governing an area historically regulated under the State's police power (see *Rice v Santa Fe Elevator Corp.*, 331 US 218,

[5]Traditionally, the word "preemption" has referred to preclusion of state law based upon express or implied Congressional intent to do so as expressed in comprehensive federal legislation. This type of "preemption" has been distinguished from the other manner of preclusion which occurs because there is a direct conflict or inconsistency between state and federal law (cf. *Consolidated Edison of N.Y. v Town of Red Hook*, 60 NY2d 99, 104-105). Both situations however, result in the supremacy of federal over state law and the term "preemption" has been used to refer to both (see *Capital Cities Cable, Inc. v Crisp*, 104 S Ct 2694, 2700; *Free v Bland*, 369 US 663, 664); for the purposes of this opinion, it is so used.

230, *supra*). The regulation of local electric utilities has been recognized as ordinarily arising under a State's police power (see *Arkansas Elec. Co-op Corp. v Arkansas Public Com'n*, ____ US ____, ____; 103 S Ct 1905, 1914).

On its appeal, the PSC maintains that section 210 of PURPA does not expressly, or impliedly by reason of a pervasive scheme of federal regulation, preempt the minimum rate provision of section 66-c of the Public Service Law. Petitioner does not contest this but, instead, asserts preemption on two other grounds: first, on the basis that there is a direct conflict between PURPA's maximum avoided-cost purchase rate and the 6 cents per kilowatt hour purchase rate set by the Public Service Law;[6] second, on the ground that the State's 6 cents per kilowatt hour rate thwarts accomplishment of the Congressional objective that consumer rate payers not be required to subsidize the development of alternate energy producers. Subsidies allegedly would occur because the utilities would pass their increased costs of purchasing power from the alternate producers through to the ultimate consumer in the form of increased rates.

The flaw in petitioner's direct conflict argument is that it is based upon the faulty assumption that the federal maximum purchase rate of avoided costs was intended to be the *absolute* ceiling on the price that could be set by either the federal *or* state regulatory authorities. This analysis begs the question of whether Congress intended only to establish a maximum rate that could be imposed by federal regulations and to leave room for the states to separately encourage alternate power production by imposing higher rates for utility purchases of power from federal qualifying facilities.

[6]Petitioner reasons that when a utility offers to purchase wholesale electricity from federal qualifying facilities at 6 cents per kilowatt hour according to the state law, it will violate the federal mandate, under PURPA, that the maximum purchase rate be avoided costs, which here, the PSC found to be 4.17 cents per kilowatt hour at certain off-peak times.

This court holds that there is no direct conflict between PURPA's maximum purchase rate and the Public Service Law's higher minimum purchase rate. The language of PURPA and its legislative history indicate that the PURPA avoided-cost rate is only the maximum in the context of the *federal* government's role in encouraging alternate power production (see 16 USC § 824a-3 [b] [it is only a "rule prescribed (by FERC) under subsection (a)" that may not require purchase rate higher than avoided cost to utility]; Joint Explanatory Statement of the Committee of Conference on PURPA, 1978 US Code Cong. & Admin. News, pp 7831-7832 [FERC regulation making full avoided costs the purchase rate was "meant to act as an upper limit on the price at which utilities can be required *under this section* to purchase electric energy", implies leaving room for requirements imposed outside this section under state law (emphasis added)].[7]

Moreover, FERC determined that independent, complimentary state regulation in the field was not supplanted by PURPA but could be used to expand the federal

[7]While not conclusive on this issue, there are numerous references in the Congressional debates and legislative history indicating Congress's recognition of the traditional role of the States in electric utility regulation and a desire not to infringe upon or impair the state role (see 124 Cong Rec 34558 [Sen. Jackson, "[T]he essential feature of the conference agreement is the limited nature of the authority granted to the FERC"]; 123 Cong Rec 32403 [Sen. Durkin, "[I] do not want to abrogate State law with respect to the regulation of utilities"]; Conference Rep. No. 95-1750, 95th Cong., 2nd Sess., reprinted in 1978 US Code Cong & Admin News, p 7831 [the limitation in § 210 of PURPA of sales by qualifying facilities at wholesale was not intended to "limit the States from allowing such sales to take place"]). PURPA has been characterized as a "limited federal regulation * * * on the relationships between cogenerators and electric utilities" (*FERC v Mississippi*, 456 US 742, 758). In addition, PURPA reserved to the States a large role in implementing, enforcing, and administering the program after FERC promulgated its regulations (see 16 USC § 824a-3 [a], [e-g]).

PURPA-based incentives.[8] As the administrative agency charged by Congress with implementation of PURPA (see 16 USC 824a-3[a], [h]), FERC's interpretation should ordinarily be deferred to (see *Zenith Radio Corp. v United States*, 437 US 443, 450; *Train v Natural Resources Defense Council*, 421 US 60, 87), unless it is arbitrary, capricious or an abuse of discretion (see *Amer. Paper Inst.*

[8]In the Preamble to FERC's regulations (45 Fed Reg at 12221-12222, § 292.304 Rates for Purchases-Relation to State Program), FERC left the States free to utilize their own means of encouraging alternate energy production, stating:

> The Commission has become aware that several States have enacted legislation requiring electric utilities in that State to purchase the electrical output of facilities * * * at rates which may differ from the rates required under the Commission's rules implementing section 210 of PURPA.
>
> This Commission has set the rate for purchases at a level which it believes appropriate to encourage cogeneration and small power production, as required by section 210 of PURPA. While the rules prescribed under section 210 of PURPA are subject to the statutory parameters, the States are free, under their own authority, to enact laws or regulations providing for rates which would result in even greater encouragement of these technologies. However, State laws or regulations which would provide rates lower than the Federal standards would fail to provide the requisite encouragement to these technologies, and must yield to Federal Law.
>
> If a State program were to provide that electric utilities must purchase power from certain types of facilities, among which are included "qualifying facilities," at a rate higher than that provided by these rules, a qualifying facility might seek to obtain the benefits of that State program. In such a case, however, the higher rates would be based on State authority to establish such rates and not on the Commission rules. * * *
>
> The Commission finds no inconsistency in a facility's taking advantage of section 210 in order to obtain one of its benefits, while relying on other authority under which to buy from or sell to a utility.

(Preamble to FERC Rules, 45 Fed Reg, 12214, 12221-12222.)

v Amer. Elec. Power Serv. Corp., 461 US ____, ____, & n 7; 103 S Ct 1921, 1927-1928, & n 7).

Neither does adherence to the Public Service Law thwart the objectives of PURPA. The purposes of both the state and federal statutes are identical; they seek to encourage the development of alternate energy production (see Public Service Law, § 66-c[1]). The state statute does not hinder the federal objective; it furthers it, by enhancing the bargaining position of the alternate energy developer through a predictable, guaranteed rate of 6 cents per kilowatt hour. The federal avoided-cost standard requires complicated calculations and may fluctuate greatly depending on, for example, the availability of inexpensive hydro-electric power, which will likely reduce the utility's avoided costs. The stability provided by the Public Service Law to the alternate energy producers reduces the perceived risk of a project, encourages investment, and facilitates financing.

Petitioner asserts, however, that there is an equally strong objective of PURPA—to avoid consumer-ratepayer subsidies of the alternate energy producer. Arguably, allowing the State to impose a higher rate than avoided cost will conflict with this objective by inevitably leading to subsidies, as the utilities will pass their increased costs of purchasing power along to the consumer.

Petitioner misconstrues the importance of this objective to the overall purpose of PURPA. The impact of the utilities' mandated purchase rate on the cost to consumer ratepayers was but one factor that FERC was obliged to consider when it established avoided costs as the maximum rate to be imposed by federal authorities (see *Amer. Paper Inst. v Amer. Elec. Power Service Corp.*, 461 US ____, ____ & n ____, 103 S Ct 1921, 1928-1929, & n 9, *supra*). The Supreme Court has noted that the PURPA requirement that FERC establish purchase rates "just and reasonable to the electric consumers," did not mandate

adoption of the lowest possible reasonable rate (see *id.* at ____, 103 S Ct at 1928, *supra*). The full-avoided-cost regulation was upheld because FERC was found to have met its obligation to *consider* the consumer's interest even though the adopted rate would not provide any ratesavings. FERC's explanation, that it was more important that the rate "provide a significant incentive for a higher growth rate" (see 45 Fed Reg at 12222-12223) and that the resulting decreased reliance on fossil fuel and increased energy efficiency would benefit the ratepayers and the nation as a whole (see *id.*), was accepted by the Court as reasonable and, therefore, was upheld (see *Amer. Paper Inst. v Amer. Elec. Power Serv. Corp.*, 461 US ____, ____, 103 S Ct 1921, 1929, *supra*). Thus, failure to achieve consumer ratesavings is not necessarily abhorrent to the primary purpose of PURPA, which is to encourage development of cogeneration and small power facilities (see *id.* at ____, 103 S Ct at 1924, *supra*).

Similarly, while it is recognized that ratesavings may not be achieved for consumers under section 66-c of the Public Service Law because the 6 cents per kilowatt hour rate may at times exceed current avoided costs, at least in the short run[9] (see Governor's Bill Jacket, [L 1981, ch 843]; Governor's Memorandum on approval of L 1981, ch 843, McKinney's Session Laws, pp 2627-2628), the rate does nevertheless further PURPA's objective because it encourages alternate energy production, and in a manner suited to the needs of this State.

In sum, as none of the criteria for preemption are present, the PSC has the authority to require utilities to offer to purchase power from federal qualifying facilities (including those which qualify under both PURPA and the Public Service Law). The PSC may also require a utility to

[9] If the price of fuels such as oil and gas goes up along with other costs of producing energy, the utilities "avoided cost" will be higher and may grow to exceed the rate of 6 cents per kilowatt hour.

offer to purchase power from federal qualifying facilities at a minimum rate of 6 cents per kilowatt hour[10] in accordance with section 66-c of the Public Service Law.

II

The second issue is whether part II of the Federal Power Act (FPA) (see 16 USC §824, et. seq.) preempts the PSC from compelling utilities to offer to purchase power from facilities that qualify only under the Public Service Law.

This court holds that it does. The FPA would also preempt state regulation of the federal qualifying facilities in New York except that they are exempted from the FPA under section 210(e) of PURPA (see 16 USC §824a-3[e]; 18 CFR 292.602). The purely state qualifying facilities, however, are not eligible for this federally authorized exemption because they are not covered by PURPA.[11]

Part II of the FPA applies "to the sale of electric energy at wholesale in interstate commerce" (16 USC § 824[b]). Such a sale is in "interstate commerce" if the electric energy is "transmitted from a State and consumed at any point outside thereof" (16 USC § 824[c]). The FPA was enacted to "fill the gap"left by the Supreme Court's decision in *Public Utilities Comm'n v Attleboro Steam & Electric Co.* (273 US 83), which held that the states lacked power to regulate *interstate* sales of electricity at wholesale. Exclusive regulatory authority was delegated to FERC under the FPA (see *New England Power Co. v New Hampshire,* 455 US 331, 340).

There is no dispute that if transactions between petitioner and purely State qualifying facilities for the purchase of electricity are *sales* at wholesale in *interstate* com-

[10]Of course, if the utility's avoided costs become higher than 6 cents per kilowatt hour, federal law would then require that the avoided-cost rate be used (see FERC Preamble, 45 Fed Reg at 12221).

[11]It is assumed that the purely state qualifying facilities discussed here are not exempt from the FPA for another reason (see 16 USC § 824 [f]), in which case they would be subject to the State Public Service Law.

merce, the FPA preempts any state regulation in the area (see *New England Power Co. v New Hampshire, supra* at p 340-341; *FPC v Southern California Edison Co.,* 376 US 205, 210).

The PSC asserts two arguments refuting FERC's exclusive jurisdiction over purely state qualifying facilities. One is that the FPA only concerns regulations of "sales" and therefore, only the "seller". Thus, it is reasoned that the PSC's attempt to regulate a utility's purchase rate is merely a permissible regulation of the "purchaser", which Congress intended to leave to the states. The second is that the energy produced by a local state qualifying facility and purchased by a state utility is admittedly a sale for resale to the utility's New York State consumers but it is not in *interstate* commerce because the energy originates and remains within the state.

As to the permissible-"purchaser"- regulation argument, there is no doubt that this State has long regulated utilities (see Public Service Law, §§ 110[4]; 66[12]) and that such regulation is "one of the most important of the functions traditionally associated with the police power of the States" (see *Arkansas Elec. Co-op v Arkansas Public Comm.,* ___ US ___, ___, 103 S Ct 1905, 1908, *supra*). Equally clear is the fact that the FPA did leave much regulation of utilities to the states and that Congress did not want to interfere with states' rights in this area (see 16 USC §§ 824[a] ["such Federal regulation, however, to extend only to those matters which are not subject to regulation by the States."], 824[b] [FPA "shall not apply to any other sale of electric energy"]). While facially appealing,[12] the argument distinguishing the admittedly preempted regulation of sellers of wholesale electricity (on-site generators) from purchasers in the same transactions (the utilities) is, upon closer examination, untenable. Such a distinction would simply achieve indirectly that which is

[12]A "sale of electric energy at wholesale" is defined as "a *sale* of electric energy *to* any *person* for resale" (16 USC § 824[d] [emphasis added]), which would imply regulation of only the seller, who sells *to* another, not the buyer who purchases *from* another.

not permitted directly (see *Northern Natural Gas Co. v State Corp. Commission of Kansas*, 372 US 84, 91-93.) In *Northern Natural Gas*, a state's attempt to require interstate pipeline companies to *purchase* gas ratably from local, state wells was rejected as an indirect attempt to impermissibly regulate wholesale prices of natural gas in interstate commerce, which could "seriously impair" FERC's ability to regulate in the field.[13]

The PSC's second argument is readily disposed of. An analysis under the FPA of whether a wholesale sale of electricity from an on-site generator to a utility is purely intrastate turns on scientific evidence regarding whether *any* of the electricity involved originates or is consumed outside the state (see *FPC v Florida Power & Light Co.*, 404 US 453, 454-455 [FERC jurisdiction upheld on basis of scientific and technical evidence that was used to determine that electrons from a Florida utility eventually flowed into Georgia because of "commingling" of electrons at the point of interconnection with Georgia utility lines]).

It may be, as the PSC contends, that sales by the purely state qualifying facilities to petitioner remain intrastate; indeed, petitioner admits that some may be.[14] However, this basis for state regulation, which requires scientific evidence regarding the flow of electricity, was not relied upon by the PSC in its decision. "A fundamental principle of administrative law long accepted by this court limits judicial review of an administrative determination solely to the grounds invoked by the agency, and if those grounds are insufficient or improper, the court is powerless to sanction the determination by substituting what it deems a more appropriate or proper basis" (*M/o Trump-Equitable Fifth Ave. Co. v Gliedman*, 57 NY2d 588, 593 [citations omitted]). The sole ground relied upon by the PSC, permissible regulation of *purchases* of wholesale electricity in interstate commerce, is erroneous, and thus, the PSC's assertion of jurisdiction over purely state qualifying facilities is preempted by the FPA.

[13]While *Northern Natural Gas* was decided under the Natural Gas Act (15 USC 717-717w), the distribution of regulatory power between the federal and state governments is the same under the FPA (see *FPC v Southern California Edison Co.*, 376 US 205, 211-212).

[14]Even if some electrons ultimately flow out of state, this state regulation may have only an incidental effect on interstate commerce while furthering legitimate local public interests and, thus, would not offend the Commerce Clause (see *Arkansas Elec Co-op Corp. v Arkansas Public Com'n*, ____ US ____, ____, 103 S Ct 1905, 1915-1918). Arguably, if the Commerce Clause is not violated, the state qualifying facility may not be subject to FERC's jurisdiction under the FPA (see *id.*).

Accordingly, the order of the Appellate Division should be modified by reinstating the determination of the Public Service Commission insofar as it permits imposition on utilities of a minimum purchase rate of 6 cents per kilowatt hour for electricity generated by federal qualifying facilities which also qualify under the Public Service Law and, as so modified, affirmed.

Judgment modified, with costs to appellant, in accordance with the opinion herein and, as so modified, affirmed. Opinion by Chief Judge Cooke. Judges Jones, Wachtler, Meyer, Simons and Kaye concur. Judge Jasen took no part.

Decided October 25, 1984

Appendix B—Opinion of the New York Supreme Court, Appellate Division, Third Judicial Department, December 30, 1983

STATE OF NEW YORK, SUPREME COURT

APPELLATE DIVISION—THIRD DEPARTMENT

#44910

IN THE MATTER

OF

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,

Petitioner,

against

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,

Respondent,

and

BROOKLYN UNION GAS COMPANY,

Intervenor-Respondent.

Argued, November 22, 1983.
Decided, December 30, 1983.

Before:

Hon. A. Franklin Mahoney,
Presiding Justice,
Hon. T. Paul Kane,
Hon. Robert G. Main,
Hon. Paul J. Yesawich, Jr.,
Hon. Leonard A. Weiss,
Associate Justices.

PROCEEDING pursuant to CPLR article 78 (transferred to the Appellate Division of the Supreme Court in the Third Judicial Department by order of the Supreme Court at Special Term, entered in Albany County) to review certain aspects of a determination of the Public Service Commission which established terms and conditions for the purchase of electricity from cogeneration and small power production facilities.

Kronish, Lieb, Shainswit, Weiner & Hellman (Bernard L. Sanoff of counsel), and Joy Tannian, Peter Garam, John D. McMahon and Celeste A. Contrucci for petitioner.

David E. Blabey (Howard J. Read of counsel), for respondent.

Cullen & Dykman (William R. Coleman, Joseph P. Stevens, James F. Matthews and Theresa Mady Grove of counsel), for intervenor-respondent.

Chadbourne, Parke, Whiteside & Wolff for American Paper Institute, Inc., *amicus curiae.*

MAIN, J.

On November 9, 1978, the Public Utility Regulatory Policies Act of 1978 (PURPA) was signed into law as part of the Federal response to the nationwide energy crisis. Section 210 of PURPA (US Code, tit 16, § 824a-3) was designed to encourage the development of alternate energy sources, and thereby decrease dependence on traditional fossil fuels, by requiring the Federal Energy Regulatory Commission (FERC) to adopt rules requiring, *inter alia*, electric utilities to purchase electric energy from any cogeneration facility or small power production facility qualifying under Federal rules[1] (US Code, tit 16, § 824a-3, subd [a]). Section 210 of PURPA further provides that the rate established by FERC for the purchase of such electricity:

"(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

"(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

"No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the in-

[1]A "cogeneration facility" is defined as one that produces both electric energy and steam or some other form of useful energy, such as heat (US Code, tit 16, § 796, subd [18], par [A]). A "small power production facility" is defined as one that has a production capacity of not more than 80 megawatts and uses biomass, waste, geothermal resources or renewable resources, such as wind, water or solar energy, to produce electric power (US Code, tit 16, § 796, subd [17], par [A]). We will refer to such facilities together as Federal qualifying facilities.

cremental cost to the electric utility of alternative electric energy"[2] (US Code, tit 16, § 824a-3, subd [b]).

This section also permits FERC to exempt Federal qualifying facilities from certain Federal and State laws governing electric utilities if such was deemed necessary to encourage cogeneration and small power production (subd [e]). Under section 210 of PURPA, State regulatory authorities are charged with implementing the rules promulgated by FERC (subd [f]). These rules, in 1980, were promulgated by FERC (18 CFR part 292) and they established the rate for the purchse of electricity from Federal qualifying facilities at the avoided cost (18 CFR 292.304[b] [2]), the statutory maximum rate, and ruled that all Federal qualifying facilities eligible for the exemption should be exempt from certain provisions of the Federal Power Act (18 CFR 292.601).

Also in 1980, New York State enacted legislation, like PURPA, designed to develop alternate energy sources by encouraging cogeneration and small hydro facilities (Public Service Law, § 66-c, subd 1). The definitions for such facilities (Public Service Law, § 2, subds 2-a—2-c) overlap aspects of the Federal definitions, but are not identical thereto.[3] The State law, as amended, further requires electric utilities to enter into long-term contracts to purchase electricity or useful thermal energy from State qualifying facilities under terms that are "just and economically reasonable to the corporation's ratepayers, non-discriminatory to [State qualifying facilities] and [in

[2]This "incremental cost" is defined as the cost to the utility of the electric energy which, but for its purchase from a Federal qualifying facility, the utility would generate or purchase from another source (US Code, tit 16, § 824a-3, subd [d]) and shall be referred to herein as either incremental cost or avoided cost.

[3]The cogeneration and small hydro facilities defined by State law shall be referred to as State qualifying facilities.

furtherance of] the public policy" behind the legislation, but at a sales price not less than 6 cents per kilowatt hour (Public Service Law, § 66-c, subd 1, par [a]).

Proceedings to implement the Federal and State legislation and regulations were held before respondent Public Service Commission (PSC) and culminated in an opinion issued May 12, 1982. On September 9, 1982, petitioner Consolidated Edison Company of New York, Inc., instituted this CPLR article 78 proceeding to review various aspects of the PSC's opinion. After this proceeding was transferred to this court, petitioner and the PSC stipulated to hold the case in abeyance pending the outcome of *American Paper Inst. v American Elec. Power Serv. Corp.* (461 US ____, 103 S Ct 1921), then before the Supreme Court and since decided. Based on the decision in *American Paper,* which upheld the validity of FERC's rules under section 210 of PURPA, and *Arkansas Elec. Coop. Corp. v Arkansas Public Serv. Comm.* (461 US ____, 103 S Ct 1905), decided the same day, petitioner dropped all but the three issues concerning the rates for the purchase of electricity from Federal and State qualifying facilities now before us. We note that we granted leave to intervene to Brooklyn Union Gas Company and leave to file a brief *amicus curiae* to American Paper Institute, Inc.

Petitioner challenges two of the PSC's determinations on pre-emption grounds. First, petitioner contends that the PSC's determination requiring it to purchase electricity from on-site generators that are not Federal qualifying facilities is invalid as contrary to the Federal Power Act (FPA) (US Code, tit. 16, § 791a *et seq.*), under which wholesale sales of electricity from on-site generators to electric utilities in interstate commerce are subject to FERC's exclusive jurisdiction (US Code, tit 16, § 824). Second, petitioner contends that the State-mandated minimum purchase rate of 6 cents per kilowatt hour is at times higher than the Federal rate of avoided cost set by FERC and, thus, is invalid as contrary to Federal law.

[1-3] Initially, we reject the procedural challenges to petitioner's claims. The PSC failed to raise at the appropriate time petitioner's alleged lack of standing and failure to exhaust its administrative remedies and, thus, we deem these challenges to be waived (see *Matter of Hilton v Dalsheim,* 81 AD2d 887, 888; *Matter of Cook v Town of New Scotland,* 75 AD2d 703, 704; see, also, CPLR 7804, subd [f]). We further note that although the PSC did not comment on the first pre-emption ground raised by petitioner, apparently because petitioner did not raise it at the time of the enactment of the State legislation before the administrative law judge's recommended decision, we shall entertain this issue because petitioner did raise it in submissions before the PSC's final opinion. Likewise, we reject Brooklyn Union's claim that petitioner's second pre-emption claim is an impermissible collateral attack on the PSC's reliance on FERC's Order No. 69 because the rule against such attacks of administrative determinations is not applicable where the agency acted outside its jurisdiction in a manner not authorized by statute (see, e.g., 2 NY Jur 2d, Administrative Law, §§ 150, 176, pp 236, 282), which is petitioner's claim herein.

[4-5] On the merits, we conclude that Federal law has pre-empted this area and that New York State law or regulations cannot require petitioner to purchase electricity from on-site generators unless they are Federal qualifying facilities or to purchase electricity from such facilities at a rate greater than the Federally mandated rate. A review of the legislative intent behind the enactment of section 210 of PURPA as well as the legislative framework of the FPA

and PURPA, leads us to this result. In reaching this conclusion, we emphasize that the policy being addressed is the Federal policy of developing alternate energy sources to combat the nationwide energy crisis and not the State policy of utility regulation. The Federal Government has undertaken substantial activity in the energy field to benefit the Nation as a whole and, where State action is contrary, it must fall (see, e.g., *Fidelity Fed. Sav. & Loan Assn. v De La Cuesta,* 458 US 141, 152-154; *Chicago & North Western Transp. Co. v Kalo Brick & Tile Co.,* 450 US 311, 317).

[4] The authority of FERC, and its predecessor the Federal Power Commission, to regulate, under the FPA, wholesale sales of electricity in interstate commerce, no matter how small the interstate effect, is well established (see, e.g., US Code, tit 16, § 824, subd [b]; *Federal Power Comm. v Florida Power & Light Co.,* 404 US 453; *Federal Power Comm. v Southern Cal. Edison Co.,* 376 US 205, 215-216). The PSC claims that the Supreme Court, in *Arkansas Elec. Coop. Corp. v Arkansas Public Serv. Comm.* (461 US ___, 103 S Ct 1905, *supra*), modified FERC's authority by permitting State regulation of wholesale sales if the impact on interstate commerce was not undue. The Supreme Court in that case, however, permitted State regulation of wholesale sales of electricity under the legislative framework of the Rural Electrification Act (REA) and not the FPA, thus rendering the case suspect as authority for modification of FERC's jurisdiction under the FPA.

The Supreme Court noted, though, that the State's authority to regulate such wholesale sales under the REA would be pre-empted if the Federal agency with jurisdiction "changes its present policy, and announces that state rate regulation of rural power cooperatives is inconsistent

with federal policy" (461 US, at p ___, 103 S Ct, at pp 1914-1915). In this case, a somewhat different scenario exists, but the Supreme Court's language is instructive. FERC, the agency which has historically regulated wholesale sales of electricity in interstate commerce, did not announce any change in its policy of exclusive jurisdiction over such wholesale sales, but merely acquired additional statutory options under PURPA. Moreover, PURPA itself, enacted against the backdrop of the FPA and FERC's exclusive jurisdiction, did not herald any changes in FERC's jurisdiction except those specifically provided in the statutory language, none of which transfers such jurisdiction to State regulatory agencies. Consequently, the PSC has no authority to act in this area.

[5] We also conclude that to the extent that the State requirement of a 6 cents per kilowatt hour minimum purchase price conflicts with the Federal rule establishing a purchase price of avoided cost, the State requirement has been pre-empted and is invalid. Our review of the legislative history of section 210 of PURPA indicates that Congress intended States to follow the Federal regulations and not depart from them, especially with regard to the purchase price provision. For example, the Joint Explanatory Statement of the Committee of Conference on PURPA stated that "[section 210] requires that States and utilities follow rules which the Federal Energy Regulatory Commission is to prescribe" (US Code Cong & Admin News, 1978, p 7831) and that "[t]his [avoided cost] limitation on the rates which may be required in purchasing [electricity under section 210] is meant to act as an upper limit on the price at which utilities can be required under this section to purchase electric energy" (*id.,* at p 7832). Thus, it is apparent that Congress did not intend for States to establish

rates in excess of the Federal rate, established as the statutory maximum of avoided cost.

This interpretation finds support in the recent Supreme Court decision in *American Paper Inst. v American Elec. Power Serv. Corp.* (461 US __, 103 S Ct 1921, *supra*). In that case, the Supreme Court interpreted the "just and reasonable to the electric consumers" clause of subdivision (b) of section 210 of PURPA as requiring consideration of rate savings for consumers (*supra*, p __, n 9, p 1929, n 9). Such savings are impossible if the State can establish rates in excess of avoided cost. We are not persuaded by the fact that the State's 6 cents per kilowatt hour rate is greater than avoided cost at only certain times, and then by only a very small amount. If we were to approve the State's 6-cent minimum in the face of the lower Federal maximum, we would be establishing a principle which would permit even higher State minimum rates despite lower avoided costs with the concomitant effect of further limiting potential rate savings for consumers. Indeed, at oral argument the PSC conceded that petitioner may have to pay more for electricity under State law than the avoided cost (see, also, Governor's approval memorandum, NY Legis Ann, 1981, pp 445-446). We decline to approve this State law in the face of contrary Congressional intent and Supreme Court language.

We further note that American Paper Institute's contention that *Federal Energy Regulatory Comm. v Mississippi* (456 US 742) recognizes PURPA's intent to provide States with an authority to go beyond the Federal standards established in section 210 of PURPA is without merit. For example, the Supreme Court's reference to PURPA as " 'cooperative federalism that allows the States, within limits established by federal minimum standards, to enact and administer their own regulatory programs, structured to meet their own particular needs' " (*supra*, at p 767) is

found in a discussion of titles I and III of PURPA, not of section 210. Likewise, the fact that FERC, in explaining its regulations, has indicated that States may prescribe purchase rates higher than avoided cost see, e.g., 45 Fed Reg 12221) does not require us to decide differently. Although administrative interpretations are usually accorded great deference, such interpretations need not be followed when contrary to legislative intent (see, e.g., *Public Serv. Comm. v Mid-Louisiana Gas Co.*, 463 US ____, ____, 103 S Ct 3024, 3035, 3037). As noted, Congress clearly intended that States follow FERC rules and that avoided cost be the maximum purchase price. Accordingly, the State minimum purchase rate of 6 cents per kilowatt hour has been pre-empted and cannot be enforced.

[6] The final challenge by petitioner is to the PSC's determination requiring it to give a capacity credit at $21 per kilowatt for electricity supplied by on-site generators during the summer peak period. The PSC's determination must be upheld if it has a rational basis and is supported by substantial evidence in the record (see, e.g., *Matter of New York State Council of Retail Merchants v Public Serv. Comm.*, 45 NY2d 661, 672). Our consideration of this issue and review of the record leads us to conclude that this determination should be upheld. The record reveals that petitioner charges its largest customers $21 per kilowatt to purchase electricity during summer peaks on the basis that they should pay for capacity costs. Although there may be some uncertainty about the power output of the on-site generators, evidence discloses that a supply of electricity at the [illegible]k period has the same effect as a customer's refraining from using electricity during that period and, thus, it is reasonable that the on-site generator supplying the electricity receive a credit for the capacity in the amount that the purchasing customer would have been

charged. This rationale is consistent with FERC's approach to alternate energy sources which have some uncertainty in their power output but which can supply maximum power during the summer peaks, such as photovoltaic cells (45 Fed Reg 12225), as well as FERC's regulation, pursuant to PURPA, that electricity be purchased at avoided cost. Thus, the PSC's determination requiring a capacity credit as noted above should be upheld as having a rational basis and support in the record.

The determination should be modified, without costs, by annulling so much thereof as asserted jurisdiction over and made rules regarding wholesale sales of electricity by non-Federal qualifying facilities and as required a minimum purchase price of electricity generated by Federal qualifying facilities in excess of avoided costs, and, as so modified, confirmed.

MAHONEY, P. J., KANE, YESAWICH, JR., and WEISS, JJ., concur.

Determination modified, without costs, by annulling so much thereof as asserted jurisdiction over and made rules regarding wholesale sales of electricity by non-Federal qualifying facilities and as required a minimum purchase price of electricity generated by Federal qualifying facilities in excess of avoided cost, and, as so modified, confirmed.

Appendix C—Final Judgment of the Court of Appeals of the State of New York, October 25, 1984

Remittitur

COURT OF APPEALS

STATE OF NEW YORK

3 No. 438

IN THE MATTER

OF

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,

Respondent,

v.

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,

Appellant,

OCCIDENTAL CHEMICAL CORPORATION,

Intervenor,

and

THE BROOKLYN UNION GAS COMPANY,

Intervenor-Respondent.

The Hon. Lawrence H. Cooke, Chief Judge, Presiding

The appellant in the above entitled appeal appeared by David E. Blabey, Esq. the respondent appeared by Joy Tannian, Peter Garam, John D. McMahon & Celeste A. Contrucci, Esqs. and Kronish, Lieb, Shainswit, Weiner &c; and Intervenor appeared by Whiteman, Osterman & Hanna, Esqs. and Sutherland, Asbill & Brennan, Esqs.

The Court, after due deliberation, orders and adjudges that the judgment is modified, with costs to appellant, in accordance with the opinion herein and, as so modified, affirmed. Opinion by Chief Judge Cooke. Judges Jones, Wachtler, Meyer, Simons and Kaye concur. Judge Jasen took no part.

The Court further orders that the papers required to be filed and this record of the proceedings in this Court be remitted to the Supreme Court, Albany County, there to be proceeded upon according to law.

I certify that the preceding contains a correct record of the proceedings in this appeal in the Court of Appeals and that the papers required to be filed are attached.

Court of Appeals, Clerk's Office, Albany, October 25, 1984

/s/DONALD M. SHERAW
DONALD M. SHERAW
Clerk of the Court

Appendix D—Opinion and Order of the Public Service Commission of the State of New York, May 12, 1982

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

COMMISSIONERS:
Paul L. Gioia, Chairman
Edward P. Larkin
Carmel Carrington Marr
Harold A. Jerry, Jr., dissenting
Anne F. Mead
Richard E. Schuler
Rosemary S. Pooler, not participating

CASE 27574—CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.—Electric Service Provided to Customers With On-Site Generation

OPINION NO. 82-10

OPINION AND ORDER ESTABLISHING RATES, CHARGES, RULES AND REGULATIONS FOR ELECTRIC SERVICE PROVIDED TO CUSTOMERS WITH ON—SITE GENERATION.

(Issued May 12, 1982)

BY THE COMMISSION:

INTRODUCTION

In our Order instituting this proceeding, we observed that the establishment of time-of-use rates for certain large commercial and industrial customers of Consolidated Edison Company of New York, Inc. (Con Edison or the

company)[1] "might have an impact on the demand for on-site generation in Con Edison's service territory and that this in turn might require changes in Con Edison's other electric service offerings."[2] We observed further:

> Consumers who are interested in generating their own electricity are likely to want to receive breakdown, reserve, or auxiliary service from Con Edison. In addition, they may be interested in selling electricity to Con Edison in times when they find that their generating capacity is more than sufficient for their needs. Con Edison currently provides back up service only under its S.C. 3 -Breakdown, Reserve, and Auxiliary Service tariffs and offers to buy electricity only from customers operating windmills. The S.C. 3 tariff requires a customer to contract for a specific amount of power, and pay a monthly demand charge for the higher of that amount or the highest actual demand over the past eleven months, whether service is taken or not. Customers also pay an energy charge based on their actual monthly consumption.
>
> The prospect of a growing demand for on-site generation and cogeneration in the City of New York and for independent generation using water power and other sources outside the City has raised a number of environmental, tax, revenue requirement, and rate design issues. Our concern here is to determine whether (1) Con Edison's tariffs are an obstacle to on-site generation, and (2) its service rates for these customers are cost justified. We want to begin the search for rate structures that properly accommodate utility customers who can sell as well as buy electricity.

[1]Case 27029, *Consolidated Edison Company of New York, Inc. -Electric Rate Structure,* Opinion No. 79-6 (issued March 15, 1979).

[2]Case 27574, *Consolidated Edison Company of New York, Inc. -On-site Generation, Order Instituting Proceeding* (issued June 22, 1979), at mimeo p. 1.

> On-site generation by utility consumers raises two kinds of rate issues. The first is the determination of the correct price for utility service which is auxiliary to, or backup for, the customer-generated power. The second is the determination of the price for electricity which the customer may sell back to the utility.
>
> * * *
>
> The potential increase in demand for on-site generation and backup service from Con Edison convinces us that a review of the rates, terms and conditions under which service is offered in this market would be worthwhile at this time. Our goal is to see that the Con Edison tariffs are neither an artificial barrier, nor a spur, to the development of on-site generation in its service territory. Of primary importance is whether the existing rate levels and design are justified by properly measured economic costs. But we will also expect the company to demonstrate that the terms and conditions under which it provides the service are neither arbitrary nor discriminatory.
>
> Our consideration of these matters will be in light of the requirements of Section 210 of the federal Public Utility Regulatory Policies Act of 1978 [PURPA]. Because policy issues of significance to our treatment of rates charged to customers with on-site generation outside Con Edison's service territory may be resolved in this case, we will permit other utilities, their customers, and other interested parties to participate in this proceeding.

Hearings in this proceeding were held in New York City and Albany on 38 days between September 25, 1979 and April 10, 1981, the first of which was a public statement hearing in the former city at which nine persons submitted

statements in support of the encouragement of on-site generation. The evidentiary record consists of 132 exhibits and 6,682 pages of testimony.

On September 21, 1981, Administrative Law Judge John T. Vernieu's Recommended Decision was issued. In it, the Judge addressed himself to the myriad of generic and company-specific issues concerning ratemaking guidelines, interconnection standards, and "social cost" issues raised by various parties to this proceeding. His decision can perhaps most concisely be described as giving substantial encouragement to the development of on-site generation, to the dissatisfaction of the utility parties but not entirely to the satisfaction of certain of the parties favoring on-site generation. Accordingly, briefs on exceptions have been received from the following parties: Department of Public Service staff (staff), Con Edison, Central Hudson Gas & Electric Corporation (Central Hudson), Niagara Mohawk Power Corporation (Niagara Mohawk), Orange and Rockland Utilities, Inc. (Orange and Rockland), Rochester Gas and Electric Corporation (RG&E), the Owners Committee on Electric Rates and the Greater New York Hospital Association (OCER), the New York State Energy Office (SEO), the City of Rochester, the Borough of Manhattan, the City of New York Energy Office (New York City), Multiple Intervenors, In-Novo Engineering and Development Company (In-Novo) and Hon. Joseph Ferris, Member of the Assembly of the State of New York. Reply briefs have been filed by staff, Con Edison, Niagara Mohawk, Orange and Rockland, RG&E, OCER, the Power Authority of the State of New York (PASNY), New York City, Multiple Intervenors and In-Novo.

In addition, comments on the Recommended Decision were filed by Long Lake Energy Corporation (Long Lake) and, jointly, Boise Cascade Corporation and International Paper Company (Boise Cascade), parties which previously had not participated in this case. Although several parties

have requested that the comments not be considered, the recommendations raised in them either have been raised by other parties (and thus must be addressed anyway) or can be at least preliminarily addressed in light of our resolution of other issues in this proceeding.

Finally, we have given consideration to the recent decision of the United States Court of Appeals for the District of Columbia in *American Electric Power Service Corporation v. Federal Energy Regulatory Commission,*[3] in which the court remanded to FERC for further consideration its rules requiring utilities (1) to pay no less than 100% of their avoided costs to on-site generators for power purchased from them (in the absence of an agreement fixing a lower amount);[4] and (2) to interconnect with on-site generators pursuant to guidelines formulated by the states.[5] Comments on this decision have been filed, in turn, by Con Edison, Assemblyman Ferris, OCER, The Brooklyn Union Gas Company, Long Lake, Boise Cascade, staff, In-Novo, the New York State Department of Law and SEO. We shall discuss this decision at the various points in our Opinion where it has a bearing on the issue under consideration.

We now turn to the various issues remaining for our resolution.

COSTING ISSUES

MARGINAL COSTS

Introduction

Section 210 of PURPA directs the Federal Energy Regulatory Commission (FERC) to formulate regulations governing the rates utilities are to pay qualifying facilities for power purchased from them. Subdivision (b) of that

[3]No. 80-1789 (D.C. Cir., January 22, 1982).
[4]18 C.F.R. §292.304(b) (2).
[5]18 C.F.R. §§292.303(c) (1).

section requires that "no such rule . . . shall provide for a rate that exceeds the incremental cost to the electric utility of alternative electric energy," and subdivision (d) thereunder provides that "the term 'incremental cost of alternative electric energy' means . . . the cost to the electric utility of the electric energy which, but for the purchase from such [qualifying facility], such utility would generate or purchase from another source."

Judge Vernieu observed as follows:

> This definition also describes the marginal or incremental costs that have been adopted by the Commission as being the costs relevant for rate design. No one challenges their role as the basis for rate design for on-site generators. The issues on which parties disagree are how to calculate these costs for on-site generation services, how to reflect them in rate design and how to reconcile marginal cost prices with revenue requirements.[6]

The costing issues raised by the parties on exceptions are basically the same as those described by the Judge. The *American Electric Power* decision has not added to or changed these issues; for even if that decision were to require us to set the price for purchases from on-site generators at some level less than 100% of avoided costs—and we do not believe that decision requires us to do so—we must still determine, as our starting point, what those costs are.

Marginal cost studies were submitted only by Con Edison and staff. These parties do not disagree about the manner in which marginal transmission capacity and distribution capacity costs should be computed. And although staff had initially maintained that certain generation capacity costs are variable at the margin, while the company maintained that none are, staff has not excepted

[6]Recommended Decision (R.D.), p. 172.

to the Judge's recommendation to exclude them from on-site generation rates on the ground that no marginal generation capacity costs are reflected in the company's existing firm service rate structure.[7]

Marginal Energy Costs

It is thus only with respect to the computation of marginal energy costs that there remains some controversy. There is, however, no controversy concerning Con Edison's marginal costs. As it had in other rate design cases, staff contended here that the price for sales to or—more likely in Con Edison's case—purchases of economy energy from the New York Power Pool is the relevant marginal energy cost for the company. This cost is termed the "financial lambda." The company agreed with this view, but the manner in which it estimated its financial lambda differed from that employed in other cases. Basically, the company averaged two amounts:

1. The New York Power Pool running cost or "Pool dispatch lambda," that is, the running cost(s) of the plant(s) on the Pool's margin at a given time; and

2. The company's internal running cost or "island lambda," that is, the cost of the plant the company would have to run to meet its load but for the interconnection with the Pool.

In the company's view, this averaged cost was a reasonable approximation of its financial lambda. Staff agreed, and employed the company's cost estimates in its rate proposals. Judge Vernieu concluded that those estimates "can be relied on in this case to develop rates."[8] No party has excepted to this conclusion.

[7]These conclusions concerning marginal transmission and generation costs may change following the conclusion of the company's pending rate design case (Case 27353, Phase II).

[8]R.D., p. 184.

The controversy concerns the Judge's resolution of the theoretical dispute between staff, on the one hand, and, on the other hand, three upstate parties concerning the proper measure of marginal energy costs for a utility that is, as Con Edison is not, a net seller of energy to the Pool. As noted, staff argued that the Pool transaction price, that is, the financial lambda, is the relevant measure of a company's opportunity cost, *i.e.*, the benefits foregone as a result of meeting an additional increment of on-system consumption. In the case of a utility which is a net seller to the Pool—the case which applies to some upstate utilities—the financial lambda represents the sum of the internal costs required to generate that increment and the share of the savings foregone because that increment could not be sold off-system. The upstate parties—Niagara Mohawk, RG&E and Multiple Intervenors—argued that only the internal costs are relevant, because the financial lambda is not, for a variety of reasons, an accurate measure of an upstate company's opportunity to sell off-system. The utilities also argued that basing payments to on-site generators on marginal energy costs thus computed would, in effect, allow the latter to benefit from the former's ability to sell power off-system.

The Judge concluded, after a lengthy and technical analysis, that the proper measure of a selling utility's marginal energy costs, which he termed its "marginal financial lambda," is in fact that suggested by Con Edison's analysis. The rationale for his conclusion is as follows:

1. The financial lambda is fixed, roughly, at the average of the seller's internal costs and the buyer's hypothetical internal costs incurred to supply the total amount of energy transacted between them.

2. The seller's costs, however, rise as it supplies more and more of that total amount. Thus, the marginal

profit the seller foregoes when it must meet an increment of on-system consumption is *not* the average margin on all sales, contrary to staff's contention.

3. Instead, the marginal opportunity cost of meeting an increment of on-system consumption is the seller's island lambda plus the change in its share of the savings resulting from its sales off-system. The change in its share of the savings, in turn, is half the difference between its island lambda (the change in costs the seller would incur without Pool operations) and the Pool dispatch lambda (the change in costs incurred to meet the total load served by the Pool). The marginal opportunity cost thus reduces to one-half the seller's island lambda plus one-half the Pool dispatch lambda—in other words, their average.[9]

The Judge did not recommend that this conclusion be adopted generically at this time; he suggested, instead, that it be explored further in connection with Niagara Mohawk's and/or RG&E's on-site generation proceedings, since those parties opposed using Pool operations for costing purposes. He did find, however, that the analysis underlying the conclusion is sufficient to warrant rejection of both staff's and the upstate parties' positions.

Staff does not disagree with the analysis; in fact, staff suggests on exceptions, the computerized model employed by Con Edison to estimate the marginal financial lambda, or similar models, can be employed for other utilities. Thus, it argues, there should be no delay in developing tariffs based on such models and the Judge's analysis.

[9]The actual calculation differs slightly from the foregoing description, because payments are also made to the Pool's transmission fund; but the basic underlying principle is not changed by the fact that these payments are made.

In their briefs on exceptions, Niagara Mohawk and RG&E both express uncertainties about the validity of the analysis; they agree only with the recommendation that the issue be considered further in their respective on-site generation proceedings. Neither party, however, suggests a method that might be employed to develop purchase rates to be effective pending the outcome of those cases. In addition, Niagara Mohawk suggests that the method used by staff in other cases of projecting forward-looking marginal costs from an historic period's data is unacceptable. Instead, it argues, it should be permitted to employ its future generation mix when developing internal costs, and it should also be permitted to use more current fuel costs when formulating purchase rates.

Multiple Intervenors stand alone in completely rejecting the propriety of computing marginal energy costs by referring to anything but a company's internal costs. According to this party, New York Power Pool transactions cannot properly be employed in this process, because economy dispatches are not physically controlled by the Pool's dispatch center. Instead, dispatches are merely scheduled by the Pool, and member utilities are at least theoretically, if not financially, free to disregard them. Moreover, it continues, Pool transactions sometimes cannot take place because of transmission constraints.

Multiple Intervenors' latter argument is misplaced; for, as Con Edison points out in response, the model it employed takes transmission constraints into account. And the former argument, that economy dispatches cannot be relied upon because they are merely scheduled rather than controlled by the Pool, forgets that economy transactions do in fact take place and that they are priced according to the dispatch schedule.[10]

[10] Identical arguments were considered and rejected by us, with more discussion, in the most recent RG&E and NYSEG electric rate design cases. *See* Case 27548, *Rochester Gas and Electric Corporation - Electric Rate Design,* Opinion No. 81-6 (issued March 18, 1981), at mimeo pp. 16-24; Case 27546, *New York State Electric & Gas Corporation - Electric Rate Design,* Opinion No. 81-21 (issued October 21, 1981), at mimeo pp. 13-24.

The remaining uncertainty about the propriety of adopting the Administrative Law Judge's analysis now concerns the availability of suitable "island" cost data for the various utilities, particulary at constrained levels of production. Assuming that models of the New York Power Pool's operations can provide these data, as staff suggests, there would be no problem with developing purchase rates, and Niagara Mohawk's request that contemporary and projected fuel and generation mix data be employed in the costing methodology would be answered. Moreover, application of the Judge's analysis now to both Niagara Mohawk and RG&E will not lead to unacceptable results. In the former's last electric rate case, we concluded that its marginal financial lambda and its financial lambda were very close;[11] and in the latter's pending electric rate case,[12] it and staff have agreed that its marginal financial lambda is, at least conceptually, the proper measure of its opportunity cost of on-system consumption.

In short, we conclude that the benefits of proceeding now with the energy cost estimation methods developed in this case warrant our doing so, even if there is a chance that later analyses may necessitate some changes in the resulting purchase rates. Accordingly, we shall adopt staff's recommendation that the costing model employed by Con Edison in this case, or a similar model capable of developing forecasted marginal financial lambdas, be used to formulate those rates for other utilities in the state.

AVOIDED COSTS

Introduction

No party excepts to the Judge's conclusion that generation and distribution capacity costs should not be reflected

[11] Case 27984, *Niagara Mohawk Power Corporation - Electric Rates,* Opinion No. 82-4 (issued March 8, 1982), at mimeo pp. 96-100.

[12] Case 28053, *Rochester Gas and Electric Corporation - Electric Rates.*

in the rates Con Edison pays for power purchased from on-site generators, because (1) as noted earlier, marginal generation costs are not reflected in its existing firm rates; and (2) distribution costs can be avoided only under certain conditions not alleged to be pertinent to Con Edison's system. Similarly, no party has contended that energy costs are not avoidable by virtue of such purchases. The parties disagree, however, about whether marginal transmission capacity costs are avoidable, as Judge Vernieu concluded. There is also some controversy, next discussed, concerning the proper measure of avoided energy costs, stemming from Long Lake's contention that the marginal energy costs of the utility to which an on-site generator is interconnected may not be the proper measure of avoidable energy costs.

Our resolution of these issues also provides the background for our consideration of the applicability of the *American Electric Power* decision to our own decision establishing rates for utilities' purchases from on-site generators, for the manner in which costs are defined as "avoidable" has an important, if not conclusive, bearing on the propriety of paying full avoided costs for such purchases. We have, accordingly, concluded our discussion of these issues by relating them to the court's decision.

Energy Costs

Apart from their disagreements about how these costs should be determined, the parties to this proceeding agree that the marginal energy costs of the utility to which an on-site generator is interconnected are the relevant measure of the avoided energy costs on the basis of which the payments to that generator are to be calculated.[13] However, Long Lake Energy Corporation, which is not a

[13] Under FERC's regulations, if both a qualifying facility and the utility with which it is interconnected agree, power generated by that facility may be delivered to a different utility, which then assumes the obligation to purchase it.

party to the proceeding but which filed comments (dated October 23, 1981) on the Recommended Decision, contends that, because of the operations of the New York Power Pool, there is only one statewide avoided energy cost: the running costs of the highest-cost generator in the state that would be operating but for the availability of economy energy through the Pool. It is this cost that Long Lake contends should be paid to on-site generators, or, at least, qualifying hydro-electric facilities. In the alternative, Long Lake argues that hydro facilities should be permitted to sell power directly to the Pool and receive, in return, a "split-savings" sale price; or that the utilities to which they are connected should be compelled to wheel the power to the highest-cost utility in the state.

If it were permissible for a qualifying facility that is connected to a utility which is selling economy energy to the Pool to sell energy, on its own behalf, directly to buying utilities, Long Lake's position would at least be possible to implement. Such sales, however, are not authorized by PURPA or by FERC's regulations implementing that Act. Long Lake's argument forgets that all sales from qualifying facilities to utilities that are connected to an interstate power grid would be subject to FERC's ratemaking jurisdiction but for the exemption that FERC's regulations grant to transactions between a qualifying facility and the utility to which it is connected. With one exception, the exemption only goes that far. Thus, the initial purchase obligation lies with that utility.

FERC's regulations authorize a qualifying facility to impose a purchase obligation on a non-connected utility only where the connected utility agrees to wheel the power. FERC has explicitly retained the ratemaking authority over such wheeling transactions where, as here, they involve utilities already subject to FERC's jurisdiction.[14] FERC cannot compel a utility to wheel power generated by a qualifying facility to a particular utility simply to stimulate production,[15] and we cannot presume to have

[14] 45 F.R. 12220 (February 25, 1980).

[15] *See* generally Federal Power Act, §§211 and 212.

greater authority over bulk transmission. Thus, to the extent that Long Lake's petition hinges on our issuing a blanket order providing for mandatory wheeling between utilities without reference to a specific on-site generation facility, it must be rejected.

Long Lake claims implementation of its request would maximize resource savings on a statewide basis. We do not agree with that contention. We conclude instead that basing purchase rates on the connected utility's avoided cost better serves that end. In the case of a qualifying facility connected to a utility that is a net buyer from the Pool, a purchase price that reflects the availability of economy energy generated by another utility will properly discourage the development of facilities that may be less efficient than those of the utility whose production is available. Where a qualifying facility is connected to a selling utility, a purchase price equal to the marginal opportunity cost will stimulate production that is assuredly less costly than the power that is displaced by that utility's sales to the Pool, which sales, in turn, are made possible by the qualifying facility's production.[16] Thus, purchase rates based on the connected utility's marginal opportunity costs will encourage resource savings while leaving the customers of the connected utility in no worse position than if the transactions with the qualifying facility had not taken place. Long Lake's proposal, on the other hand, would literally transfer unrealized resource savings to on-site generators, at the expense of utility consumers. For this reason, we must reject it.[17]

[16]This is so because the selling utility's marginal opportunity cost is, by definition, lower than the internal running cost of its transaction partner(s). Assuming that no qualifying facility would generate power in order to sell it at a loss, all power sold for a price equal to the utility's marginal opportunity cost must, *ipso facto,* be less costly to produce than the buying utility's (or utilities') power that is being displaced by the selling utility's production.

[17]The Judge suggested, however, that we nevertheless may wish to reconsider our approval of the share-the-savings pricing formula employed by the Pool's members in light of its effects on marginal energy costs. See pp. 136-137, *infra*.

Transmission Costs

The single most controverted conclusion by the Judge is that on-site generators will, by delivering power during system peak load periods, enable utilities to avoid transmission capacity costs; and that, conversely, by generating (or otherwise not taking) power to meet their own loads during peak periods, they will not impose such costs on the utility. This conclusion underlies, and gives necessary support to, the Administrative Law Judge's recommendation that capacity payments and capacity charges for back-up service be included in the rates for each summer peak period kilowatthour produced or purchased, respectively, by a qualifying facility.[18]

The utility parties object to this conclusion. As identified below, they raise the following arguments:

1. There can be no transmission cost avoidance unless each of the following criteria is satisfied:

    a. It must be possible to identify a specific, deferrable transmission project;

    b. The capacity increment supplied by one or more on-site generators is of an amount sufficient to supplant a project;

    c. The reliability of a qualifying facility must be established by its operating history; and

    d. The availability of the facility must be guaranteed for the duration of the project's deferral. It is not sufficient that power actually is delivered during peak periods; the facility must be legally obligated to deliver it.

[18]As noted earlier, the conclusion that transmission capacity costs are avoidable may change following the conclusion of the company's pending rate design case.

(Con Edison, Central Hudson, Niagara Mohawk and RG&E)

2. The record in this case demonstrates that Con Edison cannot avoid any bulk power transmission costs for at least the next ten years. (Con Edison)
3. Because bulk transmission costs are not avoidable, $14 of the $21/kW marginal transmission costs should be backed out of the capacity credits adopted by the Administrative Law Judge; and the remaining $7/kW costs should be examined on a site specific basis to determine if they, too, are not avoidable. (Con Edison)
4. In the case of a utility with a geographically widespread system, power produced by an on-site generator might not be deliverable to the areas of greatest load because of transmission constraints. In such a situation, it is self-evident that decentralized production would not enable the utility to avoid transmission costs. (Niagara Mohwak)

Staff, in response, points out that marginal transmission costs are determined by aggregate system peak demands, and that on-site generators can reduce the total peak load placed on transmission facilities either by delivering power to the utility system or by supplying power to reduce their own loads. Such decentralized generation is, in staff's view, the equivalent of not taking power during peak periods. Thus, staff continues, it would be inconsistent to charge back-up and supplementary customers, in particular, for transmission costs when they take service--as Con Edison proposes--but not credit those costs to them when they supply power. Staff also argues that paying for power delivered during peak periods on an as-delivered basis effectively differentiates between reliable and unreliable on-site generators. There is no need to commit them to deliver power day in and day out, since the peak period loads, which they may or may not affect, will continue to determine transmission costs.

Responding to Con Edison's argument that an amount less than $21/kW should be reflected in capacity credits, staff points out that the $21/kW amount is the marginal cost on which the company has proposed, in its pending rate design case, to base its rates for firm service taken during peak periods. Staff argues that it is inconsistent to argue here that some lesser amount is variable at the margin and, thus, avoidable.

Underlying the utilities' opposition to the conclusion that on-site generators can enable them to avoid transmission costs simply by delivering power during peak periods is their lack of certainty and knowledge about their dependability. Athough this is a justified concern, it does not compel a conclusion that reliability cannot be reasonably assured by means that are less stringent than the quasi-regulatory, contractual controls they propose; for utilities also face uncertainties about the demands firm service customers will place on their systems at peak times. If the payment for every kilowatthour delivered by an on-site generator during the relevant peak period includes a capacity credit, it would seem that rational on-site generators, as a group, would be encouraged to deliver power during peak periods in the same fashion as purchasers will be discouraged from using electricity at peak times if they are charged for capacity costs. In other words, as the utilities recognize, the questions of cost avoidance and the structure of purchase rates are probably highly interrelated.

At this time, there is very little experience on which to base a conclusion that one method of payment will work better than the other. It may be that experience will show that on-site generators deliver power erratically if they are paid for their capacity without contracts. On the other hand, the requirement of a contractual commitment as a condition precedent for capacity payments may discourage potentially useful on-site generation from developing. In resolving this issue, staff's principal argument bears repeating: transmission capacity costs are

determined by aggregate system peak demands. If on-site generators fail to level or reduce those demands, and thus fail to enable utilities to avoid costs, they will not receive capacity payments. If, on the other hand, they cause a downward shift in those demands, costs will be avoided even in the absence of a specific promise to do so. The on-site generation will, in other words, have value to the utilities whether or not there has been a promise to produce it. We shall, therefore, adopt the Judge's conclusion that the peak period delivery of power by on-site generators, in and of itself, can enable a utility to avoid transmission capacity costs, in the absence of clear evidence to the contrary.[19]

Relevance of Avoided Costs to Purchase Rates

The court in *American Electric Power* remanded to FERC for further consideration its rule requiring utilities to pay on-site generators 100% of their avoided costs because FERC did not, in the process of adopting that rule, give sufficient evidence of having struck a proper balance among the interests of cogenerators, the interests of utility consumers and the general public interest.[20] Although the court did not decide that full avoided cost payments could not be required--indeed, it suggested that a range of percentages bounded at the upper end by 100%

[19]In this connection, Niagara Mohwak's contention that an on-site generator that is isolated from a utility's peak loads because of transmission constraints cannot enable the utility to avoid transmission costs might warrant further examination. It should be noted, however, that the ratemaking implications of this situation are possibly more complex than Niagara Mohawk imagines, because an on-site generator that is located on the same side of a constraint as are the peak loads could deliver power to meet those loads. Unless the company can exactly match costs, charges and payments for each individual customer (whether a consumer or a small power producer), something which we doubt it can do, its proposition has little ratemaking significance.

[20]*American Electric Power Service Corporation v. FERC, supra,* Slip Op. at 13.

might be acceptable--it outlined "some additional concerns raised by the full avoided cost rule, which [FERC] should address in its subsequent rulemaking"[21] before such a requirement could be reenacted. These matters include the following:

1. Whether full avoided cost payments might stimulate the development of on-site generation in the service areas of utilities that are "subject to higher pollution control standards than are cogenerators, or [pay] taxes at a higher rate than will cogenerators," to such an extent that the (assumed) detriments of increased pollution and lost tax revenues are not offset by "sufficiently countervailing external benefits" dervied from the on-site generation.
2. Whether on-site generation stimulated by full avoided cost rates in the area served by a utility with excess capacity might result in unreasonably higher rates for the "remaining customers of the utility" (because fixed costs presumably must be spread over fewer sales).
3. Whether, "but for FERC's regulations," utilities might pay on-site generators rates set at less than full avoided costs, "under a standard industry practice," that would be no less adequate than the higher rates to stimulate on-site generation; and whether, in the same vein, "the market" might fix a lower price for purchases, both because on-site generators are not natural monopolists and because, in the court's view, utilities might not be monopsonists.[22]

The court made it clear that a mandatory full avoided cost standard might be sustainable after consideration of all the foregoing matters; it simply held that FERC had adopted its requirement without adequate discussion of them. In this proceeding, however, all of the foregoing

[21]*Id.*, p. 14.

[22]*Id.*, pp. 14-18.

matters were thoroughly litigated on the record. We conclude, upon review of that record, that the full avoided cost standard is still the proper one for purchase rates.

Our conclusion rests on the following analysis of the three matters raised by the court:

1. *Pollution and taxation.* As discussed later in this Opinion (pp. 109-123, *infra*), there are adequate non-price means for controlling the environmental impacts of on-site generation; there is no need to use pricing as a control mechanism. And so long as the difference between the tax burdens borne by utilities and on-site generators reflects a reversible legislative decision to raise revenues by taxing avoidable transactions, the potential for lost tax revenues also should not be a ratemaking matter. The principle underlying these conclusions is that economic regulatory agencies should not be constrained to act as if only they are capable of taking remedial actions in these areas, especially where legislation governing them has been, or can be, enacted where required by the public interest.[23]

2. *Excess capacity.* The court's discussion of this matter reveals its belief that the level of purchase rates will be a major, if not the principal, inducement for the development of on-site generation, and that it might be necessary to set such rates at a level below full avoided costs in order to deter some potential on-site generators from leaving the system of utilities with excess capacity. The validity of this reasoning, however, is limited, both because it is advanced without the benefit of a definition of avoided costs and because it fails to take into account the impact of retail rates. The short-run marginal costs of a utility with

[23]The court acknowledged that the costs associated with these matters "may not be easily quantifiable, especially at this initial stage of regulation." Nevertheless, the court continued, FERC "may find it possible to take them into account." *American Electric Power, supra*, Slip. Op. at 14.

substantial excess capacity are likely to be lower than the embedded costs on which its retail rates are based. Thus, if a state commission should decide to define avoided costs as short-run marginal costs, full avoided cost rates by themselves might provide little inducement for the development of on-site generation. But such generation may develop anyway if the costs of self-supply are lower than the embedded cost-based retail rates. As is discussed throughout this Opinion, these are precisely the circumstances that all parties agree apply to Con Edison. The percentage of avoided costs paid to on-site generators, therefore, may have little significance, by itself, to the retail customers of a utility with excess capacity. Or, to state it another way, the mere fact that a utility has excess capacity should not be a sufficient reason for permitting it to pay less than full avoided costs for purchases from on-site generators.

3. *Necessity for full avoided cost rates to induce on-site generation.* It is not clear why the court believed that utilities might *not* be monopsonists with respect to the on-site generators to which they are interconnected, especially since, as discussed earlier in this Opinion (pp. 13-15, *supra*), other FERC regulations not at issue in *American Electric Power* impose the primary obligation to purchase power from on-site generators only on those utilities unless they and the on-site generators agree to deliver the power to other utilities. In any event, no party contends that Con Edison is not a monopsonist; thus, the necessity for establishing some sort of legally-mandated floor under purchase rates is uncontroverted.[24] Given this fact, the in-

[24]It must be emphasized once again that on-site generators are free to offer to sell their production at a price that is lower than avoided costs. For example, a generator with a steady thermal load but varying power requirements may find it advantageous to sell its excess power at cost, thus offering the purchasing utility a bargain price when its (the utility's) marginal costs are highest in exchange for the assurance of receiving a compensatory price for sales made during periods when the utility's marginal costs are below the running costs of the on-site facility.

quiry as to the proper level of those rates reverts to the more general inquiry concerning the propriety of full avoided cost rates. The question of supply-side stimulation, in other words, has no independent bearing on the matter.

* * *

Having decided that the various concerns raised by the court in *American Electric Power* should not independently bear on the question of whether to adopt full avoided cost purchase rates, at least for New York utilities, we are left with the broader question of why avoidable costs—more precisely, marginal energy and certain marginal capacity costs—should be selected as the market mechanism for determining the amount of on-site generation that should develop.

In fairness to the court, it should be noted that much of its skepticism about FERC's avoided cost standard stemmed from that agency's lack of discussion of the justifications for such a standard, and in fairness to FERC, we should point out that it is probably not possible to write a concise discussion of the subject that would be relevant to a rule having nationwide applicability. In this state, however, our longstanding policy has been, as Judge Vernieu correctly noted,[25] that marginal costs are the costs relevant for retail rate design. Having long ago decided that a consumer's decision to use electric power should be made on the basis of his or her understanding of the marginal cost of producing it at various times of day throughout the year, we would establish a false distinction, were we to adopt purchase rates effectively signalling that power delivered during those periods is less valuable than power demanded.

The ability of on-site generators to produce power is similar to the ability not to consume power that firm customers have; and, therefore, rates for sales to and purchases from on-site generators should deviate to the least extent that is reasonable from firm rates, particularly if

[25] R.D., p. 172.

they are based upon marginal costs. The decision to consume or produce power should be motivated by the same consideration: the cost of that decision at the time it is made. Once that principle is established, the relative costs of self-supply or utility service can be intelligently weighed by each prospective on-site generator, and the market for such generation will define itself. If capital investment for the purpose of reducing energy consumption appears not to be cost effective, a customer will continue to take utility service. If, on the other hand, it does appear cost effective, a decision by the customer to invest in on-site generation will enable the utility to serve other customers' loads, and some growth in them, without extending itself at the margin. This, in turn, should lead to long-run savings for both utilities and ratepayers.

The potential for such savings far outweighs the risk, effectively embodied in the court's decision, that in the short-run ratepayers and utilities will be affected by on-site generation in the same manner as they would be if firm ratepayers decided to forgo consumption. Stated another way, the risk of ratepayer detriment apparently apprehended by the court could materialize even without the development of on-site generation, and thus should not be attributed either to it or to full avoided cost payments. On the other hand, the loss to society is clear if capacity costing $20/kW at the margin is not supplemented by capacity costing $18/kW or $19/kW simply because a utility was authorized to pay no more than $17/kW for it. Similarly, the statewide power pooling process by which marginal energy costs are measured ensures that energy production stimulated by full avoided cost payments will, directly or indirectly, displace more costly utility production and thus lower the cost at the margin of meeting all statewide demands without imposing additional costs on ratepayers. Such a benefit should not be forgone simply because purchases at full avoided costs would fail to reduce firm customers' rates in the short run.

We do not read the court's decision as requiring either result; indeed, the court characterized its decision remanding FERC's full avoided cost requirement as follows:

> We do not say, of course, that [FERC] must adopt rules which have no adverse impact on electricity consumers. But we do say that [FERC] must consider the rules' impact on these consumers and the public interest in striking the proper balance.[26]

We find, on the basis of the record before us, that setting purchase rates equal to full avoided costs—as we have defined them—will, by parallelling our policies on the development of retail rates, serve the end of optimal resource utilization without creating any short-run or long-run detriments to the interests of consumers or the general public that cannot be controlled by non-price mechanisms.

RECONCILIATION OF MARGINAL COSTS AND EMBEDDED COSTS

Con Edison's marginal costs, priced out over all consumption, are lower than the company's embedded revenue requirement. These two amounts would ordinarly be reconciled as part of the process of establishing rates for firm service. In this case, however, rates are to be determined for specialized services, namely, back-up and supplementary service to on-site generators. An issue has thus arisen as to which costs—marginal or embedded—should be reflected in those rates.

The Judge recommended that back-up rates reflect only marginal costs.[27] According to him, any benefit or burden that results from reconciling embedded and marginal costs should be conferred on all classes of ratepayers equally

[26] *American Electric Power, supra,* Slip. Op. at 15.

[27] As is discussed later in this Opinion (pp. 50-53, *infra*), the Judge did not reach this issue insofar as it concerned supplementary rates.

unless it can be shown that all classes benefit from a greater or lesser allocation to one class. For example, he continued, it would be desirable to set the price for back-up service provided by a "rising cost" utility[28] as close to marginal cost as is possible in order to discourage on-site generators from purchasing service when a more efficient use of society's resources would result if they supplied their own reliability reserves. The converse of this situation, of course, is that it would be preferable to have an on-site generator purchase back-up service from a declining cost utility rather than build it for itself, since the latter action would be wasteful.

When the need to reconcile marginal and embedded costs arises in order to design firm service rates, the method we have employed in past cases is to increase or reduce those charges and rates that are least likely to influence the amount of service a customer takes, until the sum of all revenues from all charges and rates equals the revenue requirement. In other words, an adjustment is made to those charges with respect to which consumer demand is relatively inelastic.[29] The Judge reasoned, however, that such an adjustment to back-up rates would not be proper, because even the least elastic decision for a firm service customer—whether to join the system at all—is one about which an on-site generator has some discretion. Because all customers of a utility will benefit from the encouragement of on-site generation, the Judge continued, all of them will also benefit if one class—on-site generators taking back-up service—is excused from having to contribute to the company's embedded costs.

The Judge's recommendation may be correct, but, as Con Edison and Orange and Rockland point out on excep-

[28] That is, a utility whose marginal costs exceed embedded costs.

[29] Case 27344 *et al., Orange and Rockland Utilities, Inc.-Electric Rate Design,* Opinion No. 80-35 (issued October 22, 1980), at mimeo pp. 28-31.

tions, there is little evidence on this record concerning on-site generators' demand elasticity and, therefore, there is equally little basis for concluding that all customers will benefit by setting rates closer to marginal costs for one group of customers. Orange and Rockland adds that the entire issue of marginal-to-embedded cost reconciliation—and the implications of employing alternative reconciliation procedures, including not reconciling costs for certain classes—should be explored in the context of the generic phase of Con Edison's pending rate design proceeding, and not sooner. And OCER, one of the representatives of on-site generators' interests participating in this proceeding, agrees with the companies, arguing that no record basis has been provided for relieving back-up customers from bearing a share of embedded costs.

Finally, Boise Cascade, which, although not a party to this proceeding, filed comments in response to the Recommended Decision, points out that regardless of whether unadjusted marginal costs are employed in designing back-up rates, they must be reflected in purchase rates. Thus, Boise Cascade points out, on-site generation customers of rising cost utilities will elect to take advantage of their prerogative, granted by FERC's regulations,[30] to take firm service at embedded cost-based rates while simultaneously selling all their production to the utilities at marginal cost-based rates. In other words, and contrary to the Judge's suggestion, the level of back-up rates will not be as material a consideration as he believed to on-site generation customers of rising cost companies. But to the extent that back-up rates are seen as important, Boise Cascade continues, no basis has been presented for concluding that such on-site generators should be denied the benefits of the marginal-to-embedded cost reconciliation that firm customers of rising cost companies enjoy.

As the foregoing suggests, all parties having a sufficient interest in this matter to comment on it have agreed that

[30] 18 C.F.R. §§292.304(b) (4) and 292.305(a).

back-up rates should be adjusted to reflect embedded costs. Their position seems correct. Regardless of the possible merits of the Administrative Law Judge's analysis, we agree that the departure from our usual rate-making procedures he urges should rest on a stronger evidentiary basis than this record provides. We shall, accordingly, reverse the Administrative Law Judge's decision not to adjust back-up rates to reflect embedded costs.

In staff's supplementary and back-up rate proposals, both of which we are adopting for the reasons set forth in the next part of this Opinion, the contract demand charges were the only charges adjusted in order to reconcile marginal and embedded costs. Staff preferred adjusting these, the least elastic demand charges, to adjusting customer charges (the least elastic of all charges), because it believed adjusting the latter would severely and adversely affect smaller customers. We agree with staff's goal, but not its approach; for these charges, which reflect only 50% of the company's marginal distribution costs, would also be significantly increased in the reconciliation process. We shall, therefore, direct the company to increase all demand charges by an equal percentage, or to propose an alternative means, to reconcile marginal and embedded costs in a manner that avoids harsh impacts on smaller customers.

RATE DESIGN ISSUES
RATES FOR SALES TO ON-SITE GENERATORS

Introduction

In our discussion up to this point, the terms "back-up" and "supplementary" service have been referred to without definition. At this point, it is important to define these terms as they are used in the remainder of this Opinion:

1. *Back-up service:* Back-up service is provided by a utility to *replace* energy and capacity that an on-site

generator ordinarily supplies to itself. Although FERC's regulations distinguish between services provided during scheduled and unscheduled outages at an on-site generation facility, no party proposed, or provided a cost basis for, recongizing such a distinction in the company's rates. Con Edison and staff agree that back-up service should be limited to customers with a load factor of less than 10% in both the summer and winter periods: *i.e.*, whose average load during a given period is less than 10% of its peak load during that period.

2. *Supplementary service:* Supplementary service is energy and capacity that is used by an on-site generator *in addition to* the energy and capacity the on-site generator supplies on its own.

FERC's regulations require generally that utilities serve on-site generators on a nondiscriminatory basis; in addition, they require utilities to provide back-up, supplementary and interruptible service upon request from on-site generators. The latter requirement may be waived, in whole or in part, if, after notice and opportunity for public comment, a state regulatory commission finds that implementation of it would impair a utility's ability to render service and/or unduly burden the utility.[31]

The preamble to FERC's regulations provides a great deal of background discussion for the development of rates for sales to on-site generators. With respect to the general rule, it states:

> Section 210(c) of PURPA provides that the rules requiring utilities to sell electric energy to qualifying facilities shall ensure that the rates for such sales are just and reasonable, in the public interest, and nondiscriminatory with respect to [qualifying facilities]. This section contemplates formulation of rates on

[31] 18 C.F.R. §292.305.

> the basis of traditional ratemaking (*i.e.*, cost of service) concepts.
>
> * * *
>
> [T]he rate for sales shall be the rate that would be charged to the class to which the qualifying facility would be assigned if it did not have its own generation.
>
> * * *
>
> [I]f, on the basis of accurate data and consistent system-wide costing principles, the utility demonstrates that the rate that would be charged to a comparable customer without its own generation is not appropriate, the utility may base its rates for sales upon these data and principles. The utility may only charge such rates on a nondiscriminatory basis, however, so that a cogenerator will not be singled out to lose any interclass or intraclass subsidies to which it might have been entitled had it not generated part of its electric energy needs itself.
>
> In situations where a qualifying facility simultaneously sells its output to an electric utility and purchases its requirements from that electric utility, . . . the facility's electric load is likely to have the same characteristics as the load of other non-generating customers of the utility. If the utility does not provide data showing otherwise, the appropriate rate for sales to such a facility is the rate that would be charged to a comparable customer without its own generation.[32]

With respect to rates for back-up service, FERC provides the following guidance:

> A qualifying facility is entitled to purchase back-up . . . power at a nondiscriminatory rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use

[32] 45 F.R. 12228-12229 (February 25, 1980).

of utility capacity. Thus, where the utility must reserve capacity to provide service to a qualifying facility, the costs associated with that reservation are properly recoverable from the qualifying facility, if the utility would similarly assess these costs to non-generating customers.

* * *

[R]ates for sales of back-up. . .power shall not be based, without factual data, on the assumption that forced outages or other reductions in output by each qualifying facility on an electric utility's system will occur either simultaneously or during the system peak. Like other customers, qualifying facilities may well have intraclass diversity. . . . The effect of such diversity is that an electric utility supplying back-up ...power to qualifying facilities will not have to plan for reserve capacity to serve such facilities on the assumption that every facility will use power at the same moment. . .[The regulation] prohibits utilities from basing rates on the assumption that qualifying facilities will impose demands simultaneously and at system peak unless supported by factual data.[33]

The foregoing passages state, with considerable force, that the rates for sales to qualifying facilities must follow the guidelines FERC has established. As will be explained below, the Recommended Decision adheres very closely to those guidelines.

Exceptions of In-Novo Engineering and Development Company

Intervenor In-Novo Engineering and Development Company (In-Novo) has filed a number of exceptions to the Recommended Decision, nearly all of which sound the theme that no basis has been established for adopting back-up rates that differ from the firm service rates applicable to the classes to which on-site generators would belong but for the fact that they generate power.

[33]45 F.R. 12228-12229 (February 25, 1980).

In summary form, In-Novo's exceptions are as follows:

1. The 10% load factor limitation on eligibility for back-up service is "arbitrary," based as it is on staff's observations that a well-managed on-site generation facility will be available for service at least 90% of the time. According to In-Novo, staff's evidence shows that an even greater availability rate is possible; thus, it argues, the 10% limitation is "overdesigned."

2. While back-up customers individually may have different load patterns from those of firm customers, as a class their load pattern will be similar. Thus, there is no basis for giving each group different rates.[34]

3. Revenue recovery under firm and back-up rates for customers with similar loads is divergent. In-Novo, assuming that all rates must precisely track costs at every level of consumption, contends that no cost basis for the divergent trends in revenue recovery has been established.

Although it is nowhere expressly stated, the tone of In-Novo's exceptions—particularly its contention that the 10% load factor limitation is too high and its repeated insistence that firm service rates be made available to on-site generators—suggest that it believes that the back-up rates recommended by the Judge are mandatory for certain customers. No fair reading of the Recommended Decision supports such an assumption; and, in any event, FERC's regulations providing that back-up service be made available "upon request of a qualifying facility"[35] compels a contrary result.

If, on the other hand, it is In-Novo's position that, for whatever reason, back-up rates simply should not be offered, FERC's regulation requiring that they be made

[34]In the same vein, In-Novo objects to the class-wide time-of-use metering and three-block demand charge structure recommended by the Judge for back-up service.

[35]18 C.F.R. §292.305(b)(1).

available unless offering them would jeopardize service or be unduly burdensome to Con Edison compels rejection of that position. Moreover, the rate structure recommended by the Judge adequately complies with FERC's guideline requiring "a nondiscriminatory [back-up] rate which reflects the probability that the qualifying facility will or will not contribute to the need for and the use of utility capacity."[36] In-Novo concedes the likelihood that back-up customers individually will have load characteristics different from those of individual firm customers, even if the load patterns of the two groups will not differ. If this assumption is correct—and there appears to be no reason to doubt its validity—the seasonal, time-differentiated rates recommended by the Judge should adequately recover the *group's* contribution to utility costs while, at the same time, avoiding or at least minimizing the likelihood that back-up customers who take service entirely in off-peak periods will subsidize the costs imposed by customers whose outages occur on peak. It is fair to read FERC's regulations as encouraging the development of such a rate structure.

One final point needs to be made. In-Novo's mathematical analysis, which purports to demonstrate divergent trends in revenue recovery between firm and back-up rates (specifically, Con Edison's proposed rates) proves too much. The design of firm service rates reflects class tendencies, and frequently reflects an assumption that individual and class load characteristics are more similar than they actually are. Moreover, the recovery of costs incurred on a seasonal basis frequently is distributed, in whole or in part, over an entire year. Finally, even though certain costs may not vary at all with the level of production, their recovery may be loaded on usage-sensitive rates. None of these aspects of firm service rate design is necessarily improper, but they are not usefully employed in designing back-up rates that meet FERC's

[36]45 F.R. 12228 (February 25, 1980).

guideline. In other words, the greater use, in back-up rates, of fixed charges to recover fixed costs and seasonal and time-differentiated rates to recover variable costs more clearly delineates the costs and benefits of avoiding outages of on-site generation facilities during peak periods. In-Novo's analysis demonstrates that firm service rates may be less likely to accomplish this result.

Back-Up Service

1. *Recovery of Transmission Costs*

Although exceptions concerning a number of features of the rates for back-up service recommended by Judge Vernieu have been filed, the greatest controversy concerns his recommendation that marginal transmission capacity costs imposed by back-up customers taking service during the summer peak period be recovered through peak period energy (per-kWh) charges; *i.e.*, only when power is actually taken.

Opposition to this recommendation comes from the utility parties. Their arguments recall those raised in opposition to the Judge's conclusion that the mere delivery of power during peak periods by on-site generators will enable utilities to avoid marginal transmission capacity costs: they contend, essentially, that transmission costs are incurred not only when service is actually taken, but also when the mere possibility that service may be required is established. Staff's response, which also recalls the earlier debate, is that transmission costs are determined by actually-observed peak loads, and the ability of back-up customers to avoid taking service on-peak will affect those costs.

The utilities' arguments sound the same theme. They have had very little experience serving on-site generation facilities, they point out, so it is not possible to predict their tendency to take service during peak periods.

Because of this uncertainty, the utilities continue, they will be required to provide sufficient peak load-related capacity to serve the on-site generators' full loads just in case their outages all occur on-peak. Accordingly, they reason, the least risky course would be to adopt contract demand charges that effectively guarantee the recovery of capacity costs. If the potential for over-recovery of revenues that is inherent in such a rate structure is a matter of concern, they add, the contract charges can be scaled down using a suitable coincidence factor. Only Con Edison has suggested a way to develop such a factor without the benefit of operating experience, although, as discussed below (pp. 40-42, *infra*), staff and OCER have demonstrated that the company's approach has several shortcomings.

Staff's rate design proposal, which the Judge adopted with one important modification (which will be discussed shortly), was formulated on the basis of its assumption that back-up customers will require service during peak periods at random. The rationale behind staff's proposal is easily understood: if a customer takes 1 kW of service during 100% of the hours in the (likely) peak period, there is a 100% probability that he or she has contributed one kilowatt to the utility's system peak and, accordingly, he or she should pay the full marginal transmission capacity cost. If the customer takes 1 kW during 99% of the peak hours, staff reasoned, he or she should pay slightly less; and if service is taken during only one hour, the probability that it will be the peak hour will be so greatly reduced that the customer should contribute only a few cents to marginal transmission costs. In short, staff's proposal treated a back-up customer's contribution to the utility's system peak no differently than many firm customers' contributions are treated. The current system peak consists of a multitude of small, medium and large demands, and the costs of serving it are billed to customers on the basis of usage. If back-up customers add to that peak, staff reasoned, they should be billed in the same manner.

Con Edison attempted to demonstrate before the Judge, as before us, that it would not be unreasonable to assume that back-up customers would be more likely to require utility service during peak periods than during other times. The company argued that on-site generators' peak loads will coincide with the company's peak load, contending that an examination of the load data of a sample of potential on-site generators supports this assumption. Moreover, it continued, the likelihood that only one on-site generation unit at a multiple-unit site will break down is greater than the likelihood that all units will break down at once. This being the case, the only time that such an on-site generator will require utility service is when its load is highest--a time that the company contends will coincide with its own system peak.

Staff doubts the validity of Con Edison's argument, pointing out that the company's data analysis failed to compare customers' loads at the time of its system peak with their loads at other times during the summer peak and shoulder periods. In particular, staff produced, for purposes of cross-examining the company's witness, data on the actual loads of certain potential on-site generators that showed that their loads rose to within 10% of their peak loads during periods when Con Edison's system load was not as high relative to its peak; that is, the customers had individual load curves that are flatter and broader than Con Edison's system curve. These data imply that even if such customers were to require back-up service at times when their loads were highest, as the company alleged, their calls for service would likely be at a time other than when the system load is near its peak. If those customers were required to pay contract demand charges that reflected Con Edison's assumption that they would require only peak period service, staff argued, they would be significantly overcharged.

FERC's regulations, the preamble to which is quoted earlier, require that back-up charges "shall not be based

on the assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both. . . ."[37] The company's proposal for recovering transmission costs, although premised more on the apprehension that on-site generators' outages might occur on peak rather than on the assumption that they will, nevertheless is inconsistent with those regulations. Under that proposal, the company would collect just as much revenue from a customer regardless of whether that customer's peak usage coincides with the system peak by designing contract charges on the basis of highly pessimistic expectations about back-up customers' behavior. And that customer would be charged the same amount whether he took one or many hours of peak period service, despite the fact, noted by the Judge, that the likelihood that any individual customer's demand will occur during the cost-causing peak period increases with the duration of that demand.

The distinguishing feature of staff's rate design proposal, on the other hand, is that it will collect revenues from customers in proportion to their energy usage. The actual charge per kWh can be adjusted so that the amount a typical customer will pay matches the marginal transmission costs that customer will likely cause the company to incur. It is this aspect of staff's proposal that the Judge found to be most persuasive.

Judge Vernieu did not, however, completely accept staff's proposal. Instead, he modified it to reflect partially Con Edison's concern that all calls for service during the 504-hour summer peak period will likely fall within the 89-hour "load sensitive peak" (LSP) period when the cost-causing peak is most likely to occur. Staff had designed its summer peak period energy (per-kWh) rates on the basis of its assumption that calls for service would be spread fairly evenly throughout that 504-hour period;

[37] 18 C.F.R. §292.305 (c) (1).

more specifically, staff assumed that 22% of the back-up customers' usage during the summer peak period would fall within the LSP period. Thus, staff argued, transmission costs should also be spread over a relatively large number of hours. Con Edison, while not supporting staff's proposal to recover capacity costs in energy rates, contended nevertheless that transmission costs should be spread over only 89 hours, but that the resulting (higher) energy rates should be charged for all usage during the 504-hour summer peak period, if such a rate design is adopted. For Con Edison contended that none of the back-up customers' usage would fall outside the LSP period; in other words, the company believed their usage during the remaining 415 hours of the peak period would be zero. The Judge generally favored staff's assumption, but he recommended that rates be designed on the assumption that a higher level of usage--36%--would fall within the LSP period. Neither staff nor Con Edison has specifically excepted to this decision, which we believe produces a conservative yet reasonable estimate of back-up customers' diversity that is consistent with FERC's regulations concerning the design of back-up rates. We shall, accordingly, adopt that decision.

Judge Vernieu also recommended that further exploration of this issue in other proceedings not be foreclosed. We agree with this recommendation. If greater experience with serving on-site generators supports the design of contract, ratcheted or monthly per-kW demand charges, companies should feel free to propose them. For the present, we shall adopt staff's proposal, as modified by the Judge, to recover marginal transmission capacity costs in the per-kWh charges imposed on back-up customers.

2. *Coincidence of Back-Up Customers' Demand*

Although staff of course supports the Judge's adoption of its proposal for recovering transmission costs, it argues,

along with OCER, that if demand charges are instead adopted, they should be designed to reflect an assumption that the ratio of the back-up class's maximum demand to the sum of all customers' individual maximum demands—that is, the class coincidence factor—is only 10%. Con Edison argues on exceptions for adoption of a 40% coincidence factor. Athough we have decided to adopt a back-up rate structure very similar to that proposed by staff, we shall resolve this issue as well; for it has a bearing on the design of the supplementary rates we are adopting in this Opinion, and it may also be relevant to issues that could arise in other cases.

Con Edison concedes at the outset that "the difficulty of determining appropriate coincidence factors for cogenerators is that detailed data for such a class of customers for utility back-up service are not available."[38] But it argues that the 40% factor it endorses "is based on an examination of the hours of outages" of a sample of on-site generating facilities (not on Con Edison's system) and reflects its contention that back-up customers "have exactly the same load characteristics as the SC-4 and SC-9 customer."[39]

Staff and OCER disagree with both contentions. In the first place, they argue, the company "backed into" the computation of the 40% factor in the process of designing back-up rates that would recover the same amount of revenues from an average SC-4 or SC-9 customer as would existing firm service rates. Con Edison does not dispute this claim. Secondly, staff and OCER continue, the company "tested" the validity of using a 40% factor by comparing it to a range of hypothetical on-site generators' coincidence factors that were developed on the basis of three small generator outage studies of limited scope. Thirdly, they argue, the hypothetical factors that ostensibly confirm the 40% factor are over-designed, because

[38]Con Edison Brief on Exceptions, p. 132.
[39]S.M. 623.

they reflect a level of coincidence that likely will not be exceeded more frequently than one day every ten years. As both parties point out, the one day in ten years standard was once employed by the New York Power Pool as a statewide reliability criterion, but it never was intended to apply to a single utility, much less a single group of customers. In any event, they note, the Pool's reliability criterion is now one day in two years. Thus, they conclude, the company's "confirmation" of the 40% factor incorporates an unduly discriminatory criterion.

We find staff's and OCER's arguments to be persuasive, and we agree with them that the average availability factor of 90% provides a better indicator of the coincidence of onsite generators' demands for utility service—in the absence, of course, of actual operating data—than does the company's approach. We shall, accordingly, deny Con Edison's request that a 40% coincidence factor be adopted.

3. *Rating Periods for Energy Charges*

Staff proposed, and Judge Vernieu recommended adoption of, the following seasonal and time-of-day rating periods for energy charges:

Summer: June 1 through September 30

Peak: Weekdays, 12:00 noon to 6:00 p.m.
Shoulder: Weekdays, 8:00 a.m. to 12:00 noon; 6:00 p.m. to 10:00 p.m.
Off-Peak: All other summer hours.

Winter: October 1 through May 31

Peak: Weekdays, 8:00 a.m. to 10:00 p.m.
Off-Peak: All other winter hours.

The Judge recommended that these rating periods apply to all back-up customers, regardless of the size of their loads.

Con Edison, Orange and Rockland and OCER all except to this recommendation. Con Edison contends that back-up and firm service rates should be consistently designed, pointing out that the latter rates have only two summer periods. OCER agrees, pointing out also that the current summer period begins in May and that the question of whether to shorten it to four months is at issue in Con Edison's pending rate design case. OCER also believes that another reason not to alter the existing rate design is that data on the time-of-use rates that have been in effect for certain SC-4 and SC-9 customers have not yet been evaluated. Orange and Rockland contends that there is no energy cost basis for differentiating between summer "peak" and "shoulder" periods; it should be noted, however, that the inclusion of transmission costs in the peak period does create a rate differential.

We are not persuaded by the arguments that back-up and firm rates need to have identical rating periods, for back-up customers (as well as others with on-site generation facilities) are likely to have a greater than average sophistication about matters concerning electric power. Similarly, our lack of experience with on-site generators provides little basis for preferring a five-month summer period to a four-month one, even if the former is currently in effect for firm customers; on the same basis, we can justify adopting a different summer period, for there are no data that would prove that decision wrong. The only constraint on our adopting the Judge's recommendation is a practical one: it would not be feasible to charge rates with three summer time-of-day rating periods to customers that are too small to bear the costs of metering that many periods.[40] Accordingly, we shall adopt the seasonal and time-of-day rating periods recommended by the Judge for all customers with loads of 900 kW or greater. For customers with demands under 900 kW but greater than 10 kW, time-of-use rates with four rating periods--peak and off-peak, winter and summer--will be

[40]See pp. 46-47, *infra*.

adopted. And we shall adopt the recommended four-month summer period for both groups of customers. Finally, we shall make both of these decisions applicable to the supplementary rates we are approving in this decision. To the extent they are inconsistent with these decisions, the exceptions of Con Edison, Orange and Rockland and OCER are denied.

4. *Demand Charges for Distribution Costs*

Judge Vernieu adopted, with some modifications, staff's proposal to recover marginal distribution costs through two different demand charges:

1. A *contract* charge, to recover the costs of distribution facilities that are determined by an individual customer's maximum demand.

2. A ratcheted, *as-used* (per-kW) charge, imposed only for usage during the summer peak and summer shoulder periods, to recover costs that are determined by various class and area peaks to which an individual customer may contribute. The billing determinant in any month will be the highest demand in the preceding eleven-month period or that month's demand, whichever is higher.[41]

Once again, Con Edison had proposed that all distribution costs be recovered in its contract demand charges, raising the same arguments it raised with respect to transmission costs. It repeats those arguments on exceptions, joined by Orange and Rockland. Our disposition of the transmission cost recovery issue, in which we explained our preference for as-used rates, applies to this issue as

[41]The Administrative Law Judge adopted a three-block rate structure, with block points at 10 kW and 100 kW. Apart from In-Novo, which objected generally to the adoption of back-up rates, no party opposes this structure, which we shall adopt.

well. Accordingly, we shall deny those companies' exceptions.

The Judge also rejected Con Edison's related proposal to enforce the contracted-for demand level by attaching a watt relay that would trip open whenever the customer's load exceeded that demand. Instead, he adopted staff's proposal to charge, for each kW of excess demand, twelve times the applicable monthly rate in any month in which actual demand exceeds contract demand by 10% or less, and twice that penalty if actual demand exceeds the contract level by greater than 10%.

Con Edison excepts, arguing that a watt relay is necessary to prevent overload conditions. OCER responds, correctly, that overload is no less a potential problem among firm customers, yet the company does not require watt relays generally.

In-Novo excepts to the use of percentage guidelines for excess demand, arguing that they permit a larger customer to take, in absolute numbers, more demand at the lower penalty rate than can a smaller customer. But this argument forgets that the larger customer must also contract for a far higher demand level in order to maintain this "advantage." It will obviously be less costly for customers of all sizes to keep their demands within contract levels.

We shall deny all exceptions to the demand charge structure recommended by the Administrative Law Judge. We shall, however, adopt it with the understanding that if a customer exceeds his or her contract demand and pays a penalty for having done so, the higher actual demand will become the new contract demand for the remainder of the contract's term.[42]

5. *Customer Charge*

Judge Vernieu recommended adoption of staff's $8.00 per month customer charge, of which $6.00 is for metering costs and $2.00 is for billing and maintenance. Con Edison

[42]Our resolution of these issues will also apply to supplementary rates.

contends, on exceptions, that both amounts are understated.

Turning first to the metering component, Con Edison points out that staff's $6.00 per month charge contemplated use of a General Electric TM-80 (or comparable) meter. But, the company notes, staff's witness acknowledged that it would be preferable to use a Fairchild DSU (or comparable) meter for customers with demands in excess of 900 kW; at a 23% carrying charge rate and including an annual telephone line charge of $143, the monthly metering cost would be $121. The Fairchild meter is now commercially available, the company states, and should therefore be used for larger customers. For customers taking less than 900 kW, the less expensive meter should still be employed, the company suggests, and the $6.00 per month charge is acceptable for the present. If that cost should increase, however, the company states it will seek to increase the charge accordingly.

The remaining $2.00 per month charge does not include costs associated with services, uncollectibles and customer accounting, costs which, the company contends, should be treated as customer-related. The company also claims that our Opinion No. 79-6, which directed the company to establish time-of-use rates for certain customers, required that customer-related costs not related to metering should be recovered in demand charges.[43] Accordingly, the company seeks increased non-metering charges that will not be collected as customer charges.

The exception raised with respect to the customer-related costs not related to metering, which is unopposed, is well taken and will be granted; there appears to be no reason why those costs should not be recovered in the contract demand charges proposed for back-up service. The exception raised with respect to metering costs is also unopposed, but it requires a little more discussion. For

[43]Case 27029, *Consolidated Edison Company of New York-Electric Rate Structure,* Opinion No. 79-6 (issued March 15, 1979), at mimeo pp. 19-20.

customers with loads greater than 900 kW, the more expensive Fairchild DSU (or one comparable to it) would be required to meter the three summer time-of-day rating periods we are adopting for them. One advantage of using such a meter, however, is that detailed load data can be retained and analyzed, thus facilitating future rate design efforts.[44] Accordingly, we shall allow the company to recover a portion of the metering cost that would be easily affordable for a customer with a demand of greater than 900 kW—$50 per month—as a customer charge. The remaining costs should be recovered as a common cost from all customers in the SC-4 and SC-9 classes. For the under-900 kW customers, the less expensive TM-80 meter (or a comparable model) should be employed, for only two summer time-of-day rating periods will be adopted for them.

6. *Reactive Power Charge*

"Reactive power," which is measured in kilovars, is that portion of the apparent power in a circuit that does not serve load. The other portion of apparent power is "real power," which is measured in kilowatts. Con Edison contended that the operations of on-site generators might make it necessary for Con Edison to feed additional reactive power to them. Accordingly, the company included a reactive power charge in its back-up, supplementary and purchase tariffs. Judge Vernieu recommended adoption of that charge.

We shall reverse that recommendation. We have not been provided any convincing evidence demonstrating that on-site generators will be any more responsible for Con Edison's kilovar deficiency than will firm customers, and

[44]The company will be authorized to charge a reasonable fee, probably no higher than $25, for providing customers with reports containing load data gathered from these meters.

the company does not currently charge firm customers for reactive power. Without a greater showing on the company's part, therefore, we must conclude that its proposal would treat on-site generators in a discriminatory manner without justification, in contravention of PURPA.[45]

7. *Term of Rates*

Judge Vernieu rejected Con Edison's proposal that contract charges should remain in effect for five years, in favor of a one-year term proposed by staff. Con Edison excepts, claiming that any shorter term will permit back-up customers to discontinue service before the costs of serving them are fully recovered. OCER responds that firm customers are not held to five-year contracts, even though their loads, too, may fluctuate. For example, OCER continues, a firm customer adopting a load management program may greatly reduce its demand, not unlike an on-site generator supplying less than its full requirement; yet under the company's proposal only the latter would be required to enter into a five-year contract.

Con Edison's proposal unjustifiably discriminates against on-site generators, for it is based on nothing more than unsupported apprehensions about their stability as customers. Accordingly, its exception will be denied, and the one-year term adopted by the Judge, which will apply to back-up and supplementary customers alike, will be adopted.

8. *Submetering of Back-Up Power*

Under our policies regarding the submetering of electric service, residential dwellings in multiple-dwelling buildings or complexes may not be converted from direct metering by a utility to submetering by a landlord.[46] The Public Service Law, however, does not preclude the

[45]This decision also applies to the company's supplementary and purchase tariffs.

[46]Case 26998, *Rent Inclusion and Submetering*, Opinion No. 79-24 (issued November 14, 1979), at mimeo pp. 11-15.

landlord from substituting self-generated power for utility service directly provided to tenants. If, however, back-up power provided to the on-site generation facility could be passed along to the tenants, a technically-prohibited direct metering-to-submetering conversion would occur. Accordingly, Con Edison included a provision in its back-up tariff requiring that all power provided under the tariff be used "on the same premises" and not be submetered to formerly directly-metered customers.

Although the Recommended Decision is not entirely clear on this point, the Administrative Law Judge apparently recommended that an exception to our policy be made for onsite generation customers. Con Edison, on exceptions, defends it tariff provision as "reasonable" and consistent with our policies. In-Novo attacks it as precisely the type of tariffed bar to on-site generation that we determined should be examined, and possibly modified, in this case. OCER agrees, adding that our Policy Statement was promulgated before the passage of §66-c of the Public Service Law, which section encourages on-site generation and permits the sale of electric power and steam by a non-utility generator.

Our prohibition of direct metering-to-submetering conversions is directed at a set of circumstances different from that presented by a conversion from directly-metered, firm service to submetered, self-generated service that is backed up by utility service. Application of that prohibition here may operate to preclude the development of otherwise economically viable on-site generation, because potential landlord-generators may not be able to afford the costs of supplying their own back-up reserves. Since our policy basis for prohibiting such conversions is not specifically applicable to such customers, we conclude that the prohibition is inconsistent with the policy of federal and state laws that encourage the development of on-site generation. Accordingly, we shall not extend our submetering

policy to landlords taking back-up service.[47] Con Edison's exception is therefore denied.

Supplementary Service

The Judge, finding that no evidentiary basis had been provided for implementing a separate rate design for supplementary service, recommended that such customers be provided service as firm customers. Important to his recommendation was the fact that both staff and Con Edison designed special rate proposals on the basis of their mutual assumption that supplementary customers' load patterns would be similar to those of firm customers.[48]

Only Con Edison excepts to the Judge's recommendation.[49] According to the company, the very lack of knowledge about supplementary customers' demands that necessitated basing the rate proposals on firm customers' load patterns also justifies loading the recovery of a substantial portion of the costs of serving such customers on contract demand charges.[50] In any event, the company argues, there is a "very real possibility" that supplementary customers' loads will differ from those of firm customers, since "the customer wants supplementary service precisely because it expects to use the service in a matter that is not equivalent to firm service."

In the alternative, Con Edison requests that if firm rates are charged to supplementary service customers, a special

[47]We shall, however, continue to apply that policy to landlords taking supplementary service. We shall review applications by supplementary customers for variances from that policy on a case-by-case basis.

[48]FERC's regulations implementing PURPA generally require that supplementary service be provided to qualify facilities, but they provide no guidance as to how separate rates for such service should be designed.

[49]RG&E does not oppose the recommendation as it pertains to Con Edison, but it points out that its experience providing supplementary service to one large customer suggests that separate rates can and should be designed for such service.

[50]As with its back-up rate proposal, Con Edison proposes to enforce the contracted-for demand level with a watt relay.

provision should be adopted that would charge a supplementary customer for its "demand deficiency" if it fails to maintain the same ratio of average demand to maximum demand that the average firm service customer achieves. The company also requests that its firm service demand charges, which currently are imposed only on peak period consumption, should be redesigned into peak and off-peak components in order to insure that supplementary customers that take service only during off-peak hours do not escape paying demand charges. Both of these proposals surfaced for the first time in Con Edison's Brief on Exceptions because, the company claims, it could not have anticipated that the Judge would recommend firm rates for supplementary service.

OCER provides the principal opposition to Con Edison, pointing out that both the company's original and most recent rate proposals would impose charges on on-site generators that would not be imposed on firm customers with sporadic or uncertain demands. And OCER notes that Con Edison's profession of surprise at the Judge's recommendation is somewhat disingenuous, since he adopted the position urged throughout the proceeding by, among others, OCER.

Stated simply, Con Edison has provided no basis for disturbing the recommendation that existing firm rates be charged for supplementary service, in favor of its proposed rate structure, which relies more heavily on contractual charges. The arguments the company makes here are the same as those it raised in opposition to the transmission and distribution capacity charges recommended by the Judge. They have no greater force here; the company's exceptions, accordingly, will be denied.

We do not agree with the Judge, however, that the existing firm rates should be adopted as supplementary rates instead of staff's proposal. A lack of knowledge about whether on-site generators taking supplementary service will actually develop different load patterns should not

preclude the implementation of a rate for such customers that will benefit them if they shift their loads, and thus their calls for service, away from on-peak periods. This is what staff initially proposed to do, by recommending a supplementary rate that is nothing more than a more closely cost-based form of the existing firm service rate. Under staff's proposal, customers would be subject to three demand charges: (1) a ratcheted charge for summer peak period usage to recover transmission costs; (2) a ratcheted charge for both summer peak and summer shoulder period usage to recover class peak-related distribution costs, similar to that adopted for back-up rates; and (3) a contract charge for customer peak-related distribution costs, also similar to that adopted for back-up rates. It is apparent that a supplementary customer taking service under such a rate would have an incentive to practice load management and alleviate at least some of Con Edison's concerns that the service calls of on-site generators will tend to coincide significantly with the company's system peak.

We have decided that staff's proposed rate for supplementary service, which was fully considered on the record in this proceeding, should be adopted as an alternative to simply retaining the existing firm rates.[51] We must also, therefore, reverse, on technical grounds, the Judge's recommendation that "supplementary" rates be charged to those customers, if any, who elect to take service from Con Edison under a simultaneous purchase and sale arrangement. Under FERC's regulations, such customers must be offered the firm service rates, and our decision, in contrast to the Judge's, calls for a rate for supplementary service different from that for firm service.

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[51] It should be remembered that FERC's regulations provide that service under a supplementary tariff need not be taken by on-site generators; they may elect, instead, to take firm service, at least until such time as a utility can demonstrate, with actual cost and load data, that a separate tariff for such service is required.

Finally, as we have noted at various points earlier in this Opinion, our decisions with respect to back-up rates concerning rating periods, distribution demand charges and contracts, customer charges and reactive power charges will also apply to the rates for supplementary service. We shall incorporate those decisions into a general requirement that parallel provisions in the company's back-up and supplementary tariffs should be identical, except where we have directed the company to adopt varying rates or conditions, or where differences between those services clearly warrant different provisions.

Interruptible Service

1. *Rejection of Interruptible Rates*

FERC's regulations implementing PURPA require that interruptible service be provided to a qualifying facility unless doing so would either jeopardize utility service or be unduly burdensome to the utility serving it.[52] However, apart from noting that utilities, by offering interruptible service, "assure the adequacy of reserves by arranging to reduce peak demand, rather than by adding capacity,"[53] FERC has provided no guidance as to how such rates should be designed. Indeed, the preamble to the regulations notes that "[i]f a utility is not adding capacity (whether by construction or purchase) to meet anticipated increases in peak demand, the rates charged for interruptible service might appropriately be the same as for non-interruptible services."[54]

Neither staff nor Con Edison, the only parties to submit new interruptible rate proposals, except to the Judge's conclusion that the new proposals were without cost basis

[52] 18 C.F.R. §292.305(b).

[53] 45 F.R. 12229 (February 25, 1980).

[54] *Id.*

and of little value to Con Edison.[55] The New York State Energy Office (SEO) and OCER have, however, excepted.

SEO contends, without elaboration, that new interruptible rates must be developed in this case, arguing that FERC's regulations do not sanction declining to adopt them unless a utility specifically applies for a waiver from the requirement. We do not share this interpretation. The requirement to offer various types of rates—back-up, supplementary and interruptible rates—can be waived "after notice in the area served by the electric utility and after opportunity for public comment."[56] The Order instituting this proceeding provided, *inter alia,* that interruptible rates would be examined in this case. Thus, having found no evidentiary basis for them, the Judge was correct in not adopting new interruptible rates. SEO's exception is therefore denied.

OCER contends that offering interruptible service would be of value to the company, because it would be able to curtail service during system emergencies, periods when reserve margins are tight, and fuel curtailments. OCER adds that such service might also enable the company to shed load rather than run its more expensive peaking units. We do not disagree with either of these arguments, but the record before us nevertheless provides no basis for concluding that the company's existing interruptible rates are inadequate to achieve those benefits. And OCER does not contend that back-up and supplementary rates that track costs will be so much less effective as a means to those ends that the added administrative costs necessitated by the implementation of new interruptible rates would be justified. We shall, accordingly, deny OCER's exception.

[55] We should point out, however, that interruptible service is currently available to customers under the company's firm service tarriff. The Judge's decision does not restrict or end its availability, nor is it our intention that customers with on-site generation be precluded from taking such service if they qualify for it.

[56] 18 C.F.R. §292.305(b) (2).

2. *Alternative Rate Proposal*

In lieu of recommending the adoption of interruptible rates, the Judge recommended that a voluntary back-up rate be adopted. The distinguishing features of the proposal is that the "summer peak" rate (weekdays, 12:00 noon to 6:00 p.m.) would be divided into "load-sensitive peak"[57] and "other peak" rates, with peak-related costs allocated to each period.

Con Edison and OCER oppose the proposal. Con Edison notes that the proposal mirrors a rate design that was developed but not endorsed by staff because it loaded too much revenue recovery on too narrow a period, thus exposing the company to extreme revenue instability. OCER notes also that staff's witnesses observed that the load-sensitive period cannot be identified in advance. It would be unfair, OCER argues, to adopt such a rate when a customer cannot determine, until after the fact, whether it took service during the load-sensitive peak period. Moreover, OCER continues, even if the company could anticipate that a load-sensitive peak was about to be reached, it would be extremely burdensome to notify customers in a timely fashion to shed load. OCER objects, finally, to any rate having six rating periods.

The "load-sensitive peak rate" proposal is interesting, but it would be extremely difficult to administer, at least at the outset. Given all the other new rates and tariffs that will be developed at the conclusion of this case, we believe that this proposal should be considered in a later case. Accordingly, the Judge's proposed voluntary back-up rate will not be adopted at this time.

Service to Nonqualifying Facilities

Both federal and state statutes require the sale of back-up and supplementary service to on-site generators that

[57]For purposes of this proposal, the "load-sensitive peak" period consists of the 89 hours of highest demand.

qualify for such service under the respective laws. Neither PURPA nor §66-c of the Public Service Law require that such service be provided to any other on-site facility. The issue presented here is whether non-cogenerating facilities that use conventional fuels such as diesel oil and natural gas should be deemed eligible for such service under §65 of the Public Service Law, which requires, *inter alia,* that rates for utility service not be unreasonably discriminatory.

The Judge, adopting the proposals of staff and OCER, recommended that back-up and supplementary service be made available to nonqualifying facilities on a non-discriminatory basis. In reaching this recommendation, he specifically endorsed making available back-up and supplementary, but not firm, service to hospitals with emergency generators that may, within certain guidelines, be operated to shave peak loads. He recommended termination of the company's existing back-up service classification (SC-3), which is widely viewed as an obstacle to the development of on-site generation; and he rejected the company's proposal to charge twice the applicable back-up service rate to nonqualifying facilities with a load factor in excess of 10% (those with a load factor under 10% would be provided back-up service on a non-discriminatory basis).

Con Edison excepts to the rejection of its proposal, arguing that the Judge erroneously believed that federal law required acceptance of staff's and OCER's proposals. This criticism appears correct; but the passage *in dicta* to which it refers can be disregarded without necessitating a contrary result.

Con Edison also argues, without elaboration, that the provision of back-up or supplementary service to hospitals that intend to run their generators as peak-shavers "without a full environmental analysis of the potential impact

of such facilities would be a violation of [the State Environmental Quality Review Act]." We conclude, however, that it is far from clear—especially from the company's bald assertion—that any sort of environmental analysis is required. Making new rates available to customers with their own generators does not relieve them of their obligation to comply with other federal, state, and local laws, and, as is discussed at greater length in this Opinion (pp. 109-120, *infra*), there are laws other than the Public Service Law, and agencies other than this one, that relate to and are concerned with the environmental regulation of all industrial plants, including on-site generation facilities. No evidentiary basis has been provided to support a presumption, on our part, that customers benefited by the rates adopted in this proceeding will intentionally or negligently fail to comply with all applicable laws.

We have decided to adopt the Judge's recommendation that back-up and supplementary service be provided on a nondiscriminatory basis to customers with nonqualifying facilities who elect to operate them in parallel with the company's generators for peak-shaving purposes, for we believe that §65 of the Public Service Law compels such a decision where, as here, there is no factual basis for distinguishing between qualifying and nonqualifying facilities insofar as they are *purchasers* of service. The parties should recognize, however, that we have reached this decision in light of, among other things, our decision, discussed earlier, to adopt staff's initial supplementary rate proposal, which includes time and seaonally differentiated energy charges, ratcheted transmission and distribution charges, and contract demand charges. Customers

with nonqualifying facilities who are unwilling to take the risk that their maximum demands might be billed under those rates should segregate the loads served by their generators from those served exclusively by the company and take service under two contracts: one for firm (continuous) service and one for back-up or, more likely, supplementary service. To the extent that Con Edison would preclude such customers from taking *any* back-up or supplementary service on a nondiscriminatory basis, however, its exception will be denied.[58]

Voltage Levels

No party has excepted to Judge Vernieu's recommendation that back-up and supplementary service be made available at 265/460 volts, instead of only at the standard 120/208 volts, if (1) either the company provides service at the level pursuant to the terms of its tariff, or the customer pays for 265/460 volt facilities; and (2) no backfeed of power into the company's system will occur. This recommendation will be adopted.

[58]In an ostensibly related comment, New York City requests that "[w]hatever charges are ordered for other hospitals should apply in principle to City hospitals [which are served by PASNY via Con Edison's system] and Con Ed should be ordered to adopt appropriate tariffs." Although it is difficult to determine what, exactly, the city is requesting, it appears that it concerns the company's delivery service charges, which are not at issue here.

RATES FOR PURCHASES

Introduction

Both federal and state statutes require utilities to purchase the exported production of qualifying facilities, as defined by the respective laws. FERC's regulations require that rates for purchases shall be just and reasonable to the purchasing utility's consumers, in the public interest, and nondiscriminatory toward qualifying facilities.[59] The regulations also provide, as a general rule, that those rates may not be lower than the purchasing utility's avoided costs,[60] nor need they be higher.[61] Thus, to the extent that a facility that qualifies under FERC's regulations to sell power to a utility at its avoided costs does *not* qualify, under §66-c of the Public Service Law, to sell that power for no less than 6¢ /kWh,[62] only the avoided cost rate applies.

Three broad issues are presented here:

1. How should federally-mandated avoided cost rates be designed, and what related terms and conditions should be adopted?

2. How should §66-c of the Public Service Law be implemented?

3. Should special rates be designed for purchases from hydroelectric facilities?

Federally-Mandated Purchases

The Judge endorsed the avoided cost standard for determining the minimum rate for purchases from qualifying

[59]18C.F.R. §292.304(a)(1).
[60]*Id.*, §292.304(b) (2).
[61]*Id.*, §292.304(a) (2).
[62]For example, a new oil-fired cogeneration facility.

facilities,[63] rejecting various contentions by Con Edison that some lower rate could be justified. The purchase rates he recommended include the following features:

1. The availability to all facilities of time-differentiated rates that mirror those paid by back-up customers—including credits for avoided transmission costs in the summer peak rates.

2. The availability of negotiated, hourly energy rates to facilities larger than 10,000 kW, on an optional basis.

3. The availability of either fixed energy rates for a term of two years or variable rates that change with changes in the company's fuel adjustment charge.[64]

In addition, the Judge recommended adoption of staff's proposal to impose distribution charges on qualifying facilities equal to the contract demand charges for back-up service, in order to recover the difference (in kW) between the maximum power delivered by the facility and the maximum demand for which it has contracted under the back-up service tariff.

With the exception of the avoided cost standard, none of these features is opposed by any party. We have reviewed them and found them reasonable; accordingly, we shall adopt them.

1. *Exceptions*

The exceptions taken to the Recommended Decision that are discussed in this section are relatively minor. The

[63]FERC's regulations provide that parties are free to agree to lower rates. Section 66-c neither approves nor prohibits contractual rates that are lower than 6¢/kWh.

[64]Under FERC's regulations, the selection of either option is up to the qualifying facility (18 C.F.R. §292.304(d)).

major issue now before us is whether, and for how long a period, we can or should adopt purchase rates equal to the company's avoided costs under color of federal authority in the wake of the *American Electric Power* decision. This issue is discussed in the next section. Con Edison also argues, for reasons discussed later in this Opinion (pp. 98-123, *infra*), that it should be authorized to pay qualifying facilities rates that are 15% below avoided costs. These reasons concern such matters as air pollution, taxation, and fuel usage.

Con Edison repeats its proposal, first raised before the Judge, that any qualifying facility receiving capacity payments be required to give five years' notice before discontinuing service. To insure compliance with this condition, the company would pay the first five years' worth of capacity credits into an escrow account, and it would be entitled to recoup those monies in the event of default. This argument recalls those raised in opposition to the determination that avoided transmission capacity costs can properly be computed and paid on a per-kWh basis; and, like the earlier arguments, it forgets that sytem-peak-related costs are determined by aggregate demands that are contributed to in precisely the same fashion as the credits would be paid. We shall not, therefore, adopt the company's proposal.

Con Edison also contends that FERC's regulations excuse it from purchasing power from qualifying facilities in two circumstances:

1. At times of system emergencies; or

2. At times when purchases from qualifying facilities would result in the incurrence of costs greater than those which would be incurred if the utility generated the power itself.[65]

[65]18 C.F.R. §292.304(f) (1).

An example of the second circumstance (set forth in the preamble to FERC's regulations) is the situation where power purchased from a qualifying facility would displace a light loading on a plant, and would thus hinder the start-up of that plant and/or require using quicker-starting but more expensive peaking units to meet load increases.

This provision of FERC's regulations requires state implementation, both of requirements for notice to qualifying facilities that a "no purchase" condition exists and of procedures for verifying the existence of those conditions if deemed necessary. This matter has not been discussed heretofore, and Con Edison's proposed tariff provides only that it will "notify Customers to cease supplying energy to the Company."[66] But a literal reading of the provision, which we do not endorse, might permit the company to refuse to purchase power from on-site generators at any time within a particular rating period when "spot" marginal costs are lower than the average marginal costs used to construct rates for that period, even though such conditions would occur on about 50% of the occasions when "spot" costs do not equal average costs. We conclude that a clearer and more acceptable definition of "no purchase" conditions is required. Accordingly, we shall not approve any such condition for the company's tariff at this time. Once the company is able to develop a more precise definition, we shall allow it to resubmit its proposal for our approval.

2. *The Court Decision*

As is discussed at greater length earlier in this Opinion (pp. 19-26, *supra*) the court in *American Electric Power* remanded FERC's regulation requiring utilities to pay rates equal to 100% of their avoided costs to on-site generators for power purchased from them, holding that FERC had adopted the regulation without giving sufficient consideration to its impact on utility consumers and

[66]R.D., Appendix E, p. 66 (Special Provision J).

the general public interest. As is also discussed earlier, however, the propriety of full avoided cost pricing was fully considered on this record; and we have concluded, as did Judge Vernieu, that it should be adopted.

Con Edison argues, however, that the prospective demise of the full avoided cost rule[67] will strip us of *any* authority to set purchase rates, much less rates equal to its full avoided costs. In the company's view,

> the Commission may implement PURPA only by adopting such rates as *FERC* considers to be just and reasonable. Until FERC issues revised rules, we will not know what rates FERC considers to be just and reasonable. . . . The Commission's function under PURPA is to implement FERC's policy choices and not to make policy choices of its own.[68]

Con Edison has simply misread both PURPA and FERC's regulations implementing it. First of all, while we are, indeed, *required* to implement FERC's ratemaking guidelines,[69] our involvement does not end there. PURPA clearly authorizes FERC to exempt on-site generators' sales from its own ratemaking jurisdiction under §205 of the Federal Power Act,[70] and FERC has done so[71] without making the effectiveness of that exemption contingent upon the continued validity of the full avoided cost rule. Moreover, FERC's rule requiring utilities to purchase power from on-site generators[72] (which we have adopted, as we must, under PURPA) is still in effect, as are its rules (also adopted by us pursuant to PURPA's requirement) requiring utilities to pay on-site generators rates that are

[67]Under Rule 41 of the Federal Rules of Appellate Procedure, the rule remains in effect until FERC exhausts or forgoes its rights to appellate review.

[68]Con Edison letter, March 8, 1982, p. 4, emphasis in original.

[69]PURPA, §210(f).

[70]*Id.*, §210(e) (1).

[71]18 C.F.R. §292.601.

[72]*Id.*, §292.303(a).

just and reasonable to their consumers, in the public interest, and nondiscriminatory toward qualifying facilities.[73] Even with the avoided cost standard, implementation of these rules has necessitated a great deal of dicretionary decisionmaking on our part, as has implementation of the avoided cost rule itself. Nowhere does PURPA require that we cease exercising such discretion if one of the FERC rules that we must adopt is invalidated. Finally, PURPA clearly does not require FERC to promulgate a strictly cost-based ratemaking standard, even though FERC did so. Instead, PURPA merely establishes a cost-based *parameter* that delimits *FERC's* rulemaking authority.[74]

Thus, to summarize the foregoing discussion:

1. The rates for sales from on-site generators are exempt from FERC's jurisdiction under the Federal Power Act;

2. FERC's rules implementing PURPA delegate substantially discretionary ratemaking decisions to the states;

3. PURPA's requirement that utilities purchase power from on-site generators, which ultimately must be implemented by the states, remains in effect; and

4. FERC's cost-based purchase rate guideline, which was struck down by the *American Electric Power* decision, was neither required by PURPA nor necessary to implement it.

In view of these facts, it is difficult to understand Con Edison's argument that the *American Electric Power* decision has suddenly left us without any authority to determine fair and reasonable purchase rates, especially since that decision left intact our statutory obligation to set

[73]*Id.*, §292.304(a) (1).

[74]PURPA, §210(b).

them. Nor do we find convincing the company's contention that the remaining regulations are too imprecise to be implemented: §205 of the Federal Power Act, which the company contends must now govern the rates for on-site generators' sales (notwithstanding FERC's exemption of those sales from §205), is no more precise as a delegation of authority from Congress to FERC than is PURPA §210(f) as a delegation of authority from Congress to the states via FERC.

We conclude, therefore, that we are required—and thus authorized—to continue to set rates for purchases from on-site generators, although we will not be required to set those rates equal to avoided costs if FERC's rule establishing that standard is withdrawn. Having examined the matter fully, however, we have determined that the full avoided cost standard best comports with our ratemaking policies. Accordingly, we shall adopt that standard as the basis for the rates paid to on-site generators authorized by federal law to sell power to utilities.

Public Service Law §66-c

In its Brief on Exceptions, staff sets forth the following recommendations concerning the manner in which the provisions of §66-c of the Public Service Law governing purchases from on-site generators should be implemented:

1. A minimum rate of 6¢/kWh should be established for all qualifying facilities, except new oil-fired cogeneration, with capacities of up to 80 MW.

2. Avoided cost data, on the basis of which the minimum rate should be updated, should be submitted with each major rate filing, or with filings requesting increases in automatic adjustment clauses, or with other permitted rate filings.

3. Long-term contracts should be required of utilities whenever a State qualifying facility demonstrates that a contract is necessary to encourage its development.

Long Lake objects to aspects of all three recommendations, repeating its claim, discussed earlier, that a single statewide avoided cost—which it believes exceeds 6¢/kWh—should be adopted. Long Lake also recommends that this statewide figure be updated annually outside the context of a rate case. Finally, it contends that we are required by §66-c to direct utilities to enter into long-term contracts without the burden of proving their necessity falling on qualifying facilities. We have already discussed, and rejected, the basis for Long Lake's first two arguments, but its last argument appears correct. Accordingly, we shall direct all utilities in this state to enter into long-term contracts with all qualifying facilities who request them to do so.

Con Edison vehemently objects to any implementation of §66-c in this proceeding, arguing that the law is, in various respects, unconstitutional.

The company argues, first, that hearings need to be held to interpret the 6¢/kWh minimum purchase price provision. For example, the company contends, it is unclear whether that rate is a minimum unit price for each and every kilowatthour or, as Con Edison would prefer it, an average rate for all purchases, at varying prices, over a given time period. And, it adds, the manner in which the costs of such purchases are to be recovered is not established.

Both questions can be easily resolved. The language of the statute is fairly clear:

> [T]he commission shall establish a minimum sales price for such purchased electricity . . . of at least six cents per kilowatt hour. . . .

The designation of a minimum sales price on a per-unit basis cannot easily be read to mean an average rate for all sales. The latter construction implies that the statute contemplates that utilities must reach some sort of understanding with any and every qualifying facility about the amount of energy that will be purchased in a given period—there would be no other way to determine an average rate—yet the statute clearly does *not* require that.[75] The recovery of purchased power costs also presents no problem, for §66-c is part of a statutory scheme that permits the recovery of purchased power expenses through automatic adjustment clauses.

Con Edison next argues that the minimum purchase price provision "violates fundamental constitutional principles." Again, two separate claims are raised. First, the company contends, the statute requires paying a price that may exceed purchasing utilities' avoided costs. To the extent the former exceeds the latter, it continues, there is "a confiscation of the utilities' property." But this assumes that shareholders, not ratepayers, ultimately bear those costs; as just discussed, such an assumption is wrong. Con Edison claims, secondly, that §66-c directly conflicts with §210(b) of PURPA, because it believes the latter statute fixes the maximum purchase price at a utility's avoided cost. This argument is also wrong: §210(b) provides only that *FERC* may not require a purchase price exceeding avoided costs. That agency, however, has determined that state-mandated prices exceeding avoided costs are permissible.[76]

Con Edison argues, finally, that the provision for periodic revision of the minimum purchase price is unconstitutional, since "[t]he Legislature has not specified any standards that are to guide the Commission in revising the minimum purchase price."[77] This argument, once again, forgets that §66-c is part of a statutory scheme that permits us, on our own motion or that of another party, to investigate the rates and charges of utilities over which we have jurisdiction. And the substantive guidelines set forth in §66-c (the price shall be just and economically reasonable to utility ratepayers, nondiscriminatory to on-site generators, and in furtherance of the state policy of encouraging on-site generation) are surely no less clear than those set forth in §§65, 66 and 72 of the Public Service Law. Moreover, the standard for updating the minimum price—"to reflect increases in the cost of utility generated electricity"—is more specific than some of those sections.

On the basis of the foregoing, we conclude that §66-c must be implemented in this case, as the Legislature has directed us. We shall implement that section as follows:

1. The 6¢/kWh purchase rate shall be implemented immediately as the minimum rate payable to all facilities qualified to receive it, in the absence of an agreement fixing a lower rate.[78]

2. Utility avoided costs shall be updated in each rate case.

3. Long-term contracts between utilities and qualifying facilities will be required whenever they are requested by the latter.[79]

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[75]This is not to say that the statute prohibits such an arrangement: if 6¢/kWh is "economically reasonable" to a utility's customers, and a qualifying facility willingly will sell for less, the statute would not bar such a contract.

[76]45 F.R. 12221 (February 25, 1980).

[77]Con Edison Reply Brief on Exceptions, p. 42.

[78]Pursuant to our decision here, of course, the minimum payment shall be the utility's avoided costs in any rating period when these costs (or, more specifically, the average costs for that period) exceed 6¢/kWh.

[79]If on-site generators request them, these contracts shall include escalator clauses designed to keep contract rates aligned with tariff rates.

Purchases From Hydroelectric Facilities

Long Lake, which, as noted, did not participate in the evidentiary hearings, nevertheless submitted a lengthy comment in which it recommended, essentially, that purchase rates that particularly favor hydroelectric facilities be developed apart from this proceeding. Such rates should not be considered here, Long Lake argues, because our Order instituting this case explicitly stated that the rates adopted should not be a "spur" to on-site generation; according to Long Lake, it is in fact the policy of New York to spur all the hydroelectric generation that is feasible. Besides, Long Lake adds, matters such as backup rates, New York City's air quality and fuel usage, all of which have attracted much attention here, are of little direct concern to potential operators of hydro facilities.

Long Lake also offers the following guidelines it believes should govern the development of rates for purchases from hydro facilities (some have been discussed previously):

1. The avoided cost standard should be set equal to the highest "island" marginal costs in the state.

2. Time and seasonally differentiated purchase rates should not be adopted, since they may be too complex for the developer of a hydroelectric facility to understand and, in any event, they have no bearing on the facility's ability to deliver power (the purchasing utility's needs notwithstanding).

3. The various impacts of transmission constraints on the ability to sell power should be ignored, and hydro and other small power producers should be given "first call" on the use of transmission capacity (apparently even in preference to the service obligations of the utilities that own them).

4. Wheeling of power should be required by us at rates we establish.

5. Utilities should be required to assist small power producers to reduce the latter group's costs of capital.

Needless to say, these recommendations are controversial, and some appear to run afoul of both state and federal laws. At the very least, they must be examined in evidentiary hearings in order to determine all the consequences of their adoption. For example, in the short time it had to respond to Long Lake's filing, staff found the following shortcomings:

1. The purchase rate proposals would effectively transfer the risks of hydroelectric development from the project owners to utility ratepayers.

2. Time and seasonally differentiated prices should have a greater influence on hydro operations than Long Lake suggests, since they can schedule generator and turbine maintenance for off-peak periods.

3. Levelized rates could encourage industrial owners of hydro facilities to consume the production on-peak and sell it off-peak, even though the reverse pattern might be more useful to the public.

4. Metering costs associated with time and seasonally differentiated purchase rates are small relative to project costs.

In view of the foregoing staff comments, as well as our earlier discussion of Long Lake's comments, we shall not adopt any of its proposals in this proceeding. Long Lake is free, if it wishes to have them considered, to submit them

for comment in the on-site generation rate proceedings, or subsequent rate proceedings, of the utilities to which it wishes to sell power.

DELIVERY RATES

City of Rochester's Proposal

The City of Rochester, an intervenor, proposed that the utility serving it, RG&E, be required to develop "appropriate cost-based rates for use of RG&E's distribution system to wheel electricity from the City's point of generation to its points of consumption."[80] The City plans to build its own generating plant—it is not entirely clear whether it would be a qualifying facility for which we are authorized to set purchase rates—and it wants RG&E to formulate a rate for delivering production from that plant to each street lighting fixture in the City, most of which are owned by RG&E. But this would not be a bulk transmission of power from one point of interconnection to another, which is the commonly accepted notion of wheeling, for RG&E's street lighting plant is served directly from, and in common with, its distribution system. Thus, were the City's request granted, it would be necessary to examine the company's distribution system in far greater detail than either the City has done or the company is prepared to do, in order to determine the costs of such a "delivery." In exchange for paying these costs, the City proposes, the energy it generates would be directly "imputed" to street lighting, and the amount of energy it now purchases from RG&E would, apparently, be constructively reduced.

Judge Vernieu rejected Rochester's proposal because he believed it to be a scheme to take service from RG&E's system without paying for it. The City excepts, arguing that it is willing to pay a fair price for such delivery service, and that it would be satisfied for the present if we

[80]City of Rochester Brief on Exceptions, p. 2.

would merely direct RG&E to examine such a rate in its on-site generation case.

In response, RG&E points out that the operating arrangement the City seeks would not be different from a conventional interconnection with utility purchases of exported power were it not for the City's insistence on a more complicated service arrangement which, additionally, the company does not believe would be economically more advantageous to the City than a straight sale of power at the company's avoided costs (or 6¢/kWh, if that rate is higher and the facility qualifies for it under state law).

It is indeed difficult to see how the City could benefit more from its proposal than from selling power directly to the company. Because RG&E is a "rising cost" company, the price it pays for an on-site generator's production might exceed the retail rate it charges for sales to that facility. Were the City to produce as much energy as it consumes for street lighting, it might end up earning a net profit on that energy, leaving to be paid only the various street lighting facility charges that it would have to pay even if its own proposal were adopted. Under the City's plan, it would be credited for energy at the retail rate, but it would have to pay delivery charges.

In view of the foregoing, we shall deny the City of Rochester's exception. The City has provided little if any basis for concluding that this matter needs to be explored further. The City is, of course, free to come back at any time with a clearer proposal; but we shall not, for the time being, impose on RG&E the burden of going forward with the proposal submitted here.

New York City's Exception

In the proceedings before the Judge, the Power Authority of the State of New York (PASNY) sought the development of delivery service rates for its customers

with on-site generation. The Judge rejected the request as unsupported, but he did note that Con Edison agreed to attempt to reach an agreement with PASNY regarding such rates within six months after the completion of this case. And he urged "affected parties to enter into the required dialogue to bring this matter to a satisfactory determination at the earliest possible date."[81]

Con Edison already provides what would be the reverse of the requested service; that is, the company delivers power from PASNY's generators to the Authority's customers. The rates for this service, although designed and determined in Con Edison rate proceedings, are subject to FERC's ratemaking jurisdiction.[82] Similarly, the rates Con Edison would charge for delivering to PASNY power generated by the Authority's customers are apparently subject to the federal agency's approval.[83] An important condition precedent to the provision of the latter service, however, is that both Con Edison and the on-site generators must agree to provide it.[84] Should either party not agree, Con Edison would retain the obligation to purchase the exported power, provided, of course, that the on-site generator is a qualifying facility.

In its Brief on Exceptions, New York City argues for the first time that Con Edison be required to develop delivery rates similar to those sought by the City of Rochester. No evidence concerning the cost basis for such charges was submitted in this case; nevertheless, New York City urges, the charges should be based on the "normal terms and conditions" for transmission services provided to members of the New York Power Pool as well as "the terms and conditions for distribution and customer costs normally imposed for the class of services involved."[85] Underlying this request is New York City's dissatisfaction

[81] R.D., p. 269.
[82] *See* New York City Brief on Exceptions, Appendix C.
[83] 45 F.R. 12220 (February 25, 1980).
[84] 18 C.F.R. §292.303(d).
[85] New York City Brief on Exceptions, p. 6.

with the existing PASNY delivery charges, which the City views as "quite high."

New York City also requests that "liberal wheeling rules" also be adopted, so that it can draw on power that may be produced at the City's upstate waterworks. The City also envisions wheeling service that would enable it to shop around for "least cost power," such as Canadian hydroelectric power. As discussed elsewhere in this analysis, however, these requests are well outside the scope of this case.

The principal difference between Rochester's and New York's requests is that the latter's utility already has developed a schedule of charges for the delivery of non-utility power to municipal facilities, so the burden of implementing the latter request might not be as great. But New York's dissatisfaction with those charges suggests that it also seeks a new rate structure, the support for which, however, is lacking from this record. Moreover, the need for such rates at this time is less than clear: the City alleges only that it "may choose to cogenerate in City buildings or at garbage burning facilities, or to produce power from small hydroelectric, wind or photovoltaic facilities."[86] And, finally, the same observation made about Rochester's proposal applies here as well: it is unclear whether the City would be better off delivering power under its proposal or simply selling it to Con Edison at the utility's avoided costs while purchasing energy from PASNY.

For all of the foregoing reasons, New York City's request will be rejected at this time for want of an evidentiary basis. The City is, of course, free to return with a proposal once it has a clearer idea of the types and locations of the generating facilities it plans to build.

[86] *Id.*, p. 4.

INTERCONNECTION ISSUES

INTRODUCTION

As noted earlier in this Opinion, the court in the *American Electric Power* case remanded to FERC its regulation generally imposing on utilities an obligation to interconnect with on-site generators. Con Edison argues that the court's decision effectively precludes us from requiring it to interconnect with on-site generators or establishing standards for those interconnections. We disagree. There is nothing in PURPA or the court's decision to suggest that Congress intended to preempt our inherent jurisdiction over utility connections with retail customers simply because the connections at issue here would now enable parallel operations and the export of power from customers to utilities. And we have been directed by the Legislature to require the utilities subject to our jurisdiction to offer to purchase power from on-site generators.[87] Assuming those offers are accepted, some means for permitting the sales to take place must be provided; these means, of course, are interconnections. We are not free to decide not to follow an explicit legislative mandate. Accordingly, we shall proceed with our consideration of the interconnection issues raised in this case.

VOLTAGE LEVELS

Introduction

The issues raised with respect to the feasibility of interconnecting with Con Edison's system at various voltage levels are of concern only to those on-site generators that desire to export power to the company. Any customer whose generating facility serves a segregated load, and thus would not be interconnected, will not be affected by

[87] Public Service Law, §66-c.

the limitations discussed in the following section of this Opinion.

Secondary Network

As described in greater detail in the Recommended Decision, over 80% of Con Edison's peak load is served via a complex secondary distribution network that is designed to draw on several power sources simultaneously in order to minimize the likelihood of outages. As load on the network increases, additional power can be imported at any one (or more) of a number of points; and if one of the power sources is removed, one section of the network can energize another. When load drops, however, the power sources must be removed in order to prevent feeding power between sources ("backfeed"). If power production is not reduced, a relay (called a "network protector") trips open to prevent backfeed.

Balancing power and load on the secondary network requires control. The introduction of on-site generation capable of exporting power to the network entails a loss of control, to the extent that such power production cannot be coordinated with both the company's production and changes in load levels. Such coordination is not practically achievable at this time. The export of on-site power production thus creates the risk that power will exceed load and that, as a consequence, backfeed will occur, tripping open network protectors. For this reason, Judge Vernieu concluded that "the record fully supports the Con Edison and Staff positions that interconnection of [on-site generation] facilities at the Con Edison secondary network grid [for the purpose of delivering power to Con Edison] not be required at this time.[88]

Another potential problem stemming from the company's lack of control over on-site generators' deliveries of power is safety-related. When the company's maintenance

[88] R.D., p. 37.

crews work on a section of the network, they first de-energize that section by removing all power sources. There is some concern that the company's crews may not be able to disconnect the on-site generators' feeders and thus may be exposed to electric currents while servicing the network.

Con Edison's request that we make it clear that the company need not interconnect with an on-site generation facility at the secondary network level where there is a possibility that any backfeed, intentional or unintentional, can occur has drawn it and staff into a disagreement about what kinds of risks of unintentional backfeed the company should be required to assume. According to the company, unintentional backfeed can occur at any site where power production exceeds load; accordingly, it does not believe it should be required to interconnect with on-site generators at such sites. Staff argues that interconnection should be required with customers having any mix of capacity and load, so long as the customer installs a reverse power relay—*i.e.*, a network protector—to prevent backfeed.

Con Edison opposes staff's position, contending that it was advanced for the first time in staff's reply brief on exceptions. The company points out that its electrical engineering witness examined the possibility of installing protectors at each on-site generation facility but rejected that option because there would be no assurances that the protectors would be properly maintained. According to the company, it diligently maintains some 20,000 network protectors, yet it nevertheless encounters problems with some that fail to open when backfeed occurs.

It is apparent from this exchange that Con Edison does not take the position the backfeed cannot be prevented by properly-maintained protectors; and it is equally apparent that staff does not contend that the company should interconnect with an on-site generator where, in staff's view, there is a risk of backfeed. Our problem, however, is determining how to ensure that it is prevented.

We conclude that any customer willing to agree to (1) install a protector in a manner and location specified by the company; (2) set it at a sensitivity level specified by the company; (3) maintain it according to a schedule and standards specified by the company (even if they reasonably exceed the company's); and (4) forgo its right to interconnection if it fails to comply with any of the foregoing terms should be permitted to interconnect with the company regardless of its mix of production and load. It would follow that interconnections should also be accorded to customers seeking arrangements that are, from the company's point of view, more secure. Such arrangements might include having the company both own and maintain the protector, or simply maintaining the customer's protector.[89]

The company should, therefore, assume the obligation to interconnect with on-site generators at its distribution network. We see no need to have each interconnection agreement brought before us for approval, but we shall mediate any disagreements between the company and its customers concerning either the costs of or the adequacy of the safeguards incorporated into a proposed interconnection. To the extent that the Recommended Decision is inconsistent with this conclusion, we shall not adopt it.

Two intervenors, New York City and Assemblyman Ferris, have excepted to Judge Vernieu's conclusion; these parties apparently support less restrictive interconnection requirements than we are prepared to adopt at this time. New York City complains that "[t]he effect of the ALJ's decision is to make it difficult or impossible for inner city connections to be made and to have medium-sized facilities anywhere in New York City. One suspects that this is precisely what Con Ed had in mind . . . ."[90] Nevertheless, the City contends, "[e]ven within the scope of the ALJ's decision, it would appear reasonable to allow connection to the Con Ed network where there is no

[89] The customer would bear all costs in either case.

[90] New York City Brief on Exceptions, p. 13.

backfeeding of power or the load [sic] is relatively small.''[91] But the City's recommendation goes further:

> [W]e would urge that direct backfeed, through the secondary network, be permitted. In all but a few sites, which could be excluded on a case-by-case basis, the electricity backfed *would be absorbed locally before it could trigger a network protector.* Staff Witness Lutzy noted these points but chose to rely on the "expertise" of Con Ed.
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> * * *
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> Con Ed argues that with such direct interconnection to the secondary network, the backfeed power may not be absorbed locally. This might result in tripping network protectors and disrupting network symmetry. However, as noted above, nowhere is there empirical evidence supporting the probability of such [occurrences]. *In the absence of such data,* no interconnections should be automatically disallowed and smaller ones (below 500 KW net sales) should be allowed *unless the utility establishes its case.*[92]

Although Con Edison correctly contends, in response to these essentially factual assertions and allegations, that New York City neither sponsored evidence nor even appeared at the hearings at which interconnection issues were examined, we shall not summarily dismiss them, as the company urges. We believe, instead that it would be useful to consider them in light of the testimony of staff's electrical engineering witness which the City alternately relies on and criticizes. His direct testimony is as follows:

Q. Based on the potential problems outlined with respect to interconnections of decentralized

[91] *Id.*

[92] *Id.*, pp. 14-15, emphasis supplied.

generating facilities to the secondary network grid . . ., do you agree with the company's proposed prohibition of such interconnections?

A. Not completely. I agree that the potential may exist for all these problems to occur if indiscriminate interconnections were permitted. In a strict technical sense, however, it cannot be said that each individual potential interconnection with the network system will necessarily violate those fundamental operating principles. It should be recognized that the number of applications which will *not* result in a direct violation of fundamental network operating principles may be few in number.

Q. Under what circumstances could an individual decentralized generating unit be interconnected to the network grid . . . without violating fundamental network operating principles?

A. Theoretically, specific applications could be interconnected at the secondary network grid level if it could be shown that unacceptable operations of the secondary network grid cables and protective equipment would not result. However, based upon my review of what would be required in order to make this determination, signicant monitoring of network loads would be necessary both before and during the generator's operation. For example, network loads in the vicinity of the proposed generator would have to be monitored hour-by-hour both daily and seasonally on the grid between the proposed generator and the nearest existing network protectors. The loads on these relatively small segments of the network are not typically monitored by the company in the normal course of evaluating an individual customer's requirements.

Implementation of explicit operating schedules which would attempt to match an on-site generator's net output to the local network loads would be ludicrous since it would be impossible to predict network load on a day-to-day, hour-by-hour basis. In light of this, I do not recommend that the company be required to entertain applications for interconnections of facilities for the purpose of feeding power into Con Edison's secondary network grid.[93]

Stated simply, the data that New York City would require Con Edison to supply before it could *refuse* to provide an interconnection are the very data which staff's witness said would be (1) required before interconnections with backfeed potential could be *permitted* (without imperiling operating reliability), but (2) nearly impossible to collect. And Con Edison adds that the City's suggestion that 500 kW of backfeed could be accommodated is unsupported, given that most of its network protectors are, properly, set to open if they encounter backfeed of between 1.2 kW and 1.5 kW.

New York City, joined by Assemblyman Ferris, also complains about the fact that staff's and Con Edison's witnesses reached similar conclusions about the feasibility of interconnections at the secondary network. In the City's view, their agreement bespeaks a "lack of independent analysis" on staff's part, while Mr. Ferris believes that it demonstrates the need to "hire additional qualified engineering personnel to improve its ability to evaluate the feasibility of applications for interconnection to the Con Edison grid."[94] Neither complaint has merit. The agreement they find so repugnant represents nothing more than a common understanding of the operating realities of the network, reached independently by two experienced electrical engineers. While their agreement has been criticized on brief by the intervenors, the criticisms lack the support of competent testimony or record evidence.

[93] S.M. 2922-2924, emphasis supplied.

[94] Assemblyman Ferris Brief on Exceptions, p. 7.

Mr. Ferris also requests that we "initiate a study of the design of the Con Ed distribution system, perhaps in cooperation with PASNY and the New York State Energy Research and Development Authority, to determine how to expand the capacity of Con Ed's distribution system to receive power from on-site generators."[95] As the foregoing excerpt from staff's testimony shows, however, it is not the system's capacity that is the impediment to interconnection, but rather the need to balance power and load at all times, including off-peak times. There is, accordingly, no need for such a study.

Primary Feeders

Primary feeders connect distribution substations to the secondary distribution network. Although Con Edison initially proposed to prohibit any interconnections at such feeders, staff pointed out that a limited number of such interconnections might be accommodated, even if there were a potential for backfeeding power into the company's system. Staff's witness explained as follows:

> For interconnections to network primary feeders, only those installations which did not unacceptably affect network symmetry or the balanced loading on transformers should be considered. The company indicated that an on-site generator could either enhance or detract network symmetry (SM-2225). It must be recognized that even those installations which could be shown to have no unacceptable effects on network symmetry, would create additional burdens to the company in servicing the network feeders due to the requirement to manually disconnect such generation to assure deenergization.

[95] *Id.*, pp. 7-8

Q. Could this network feeder servicing problem be controlled by the company such that its impacts would be mitigated?

A. It may be possible in some instances to identify a specific feeder or feeders within a given network area which could accommodate an increment of generating capacity without affecting the overall symmetry of the network. There may be several areas, however, in which there are no feeders which could acceptably accommodate back-fed power within this [criterion]. Since there will only likely be a limited number of network feeders which meet this general [criterion], the overall impacts on network feeder servicing would be limited to only those feeders identified. Furthermore, the decentralized generator should be required to provide critical disconnecting equipment in an area completely accessible to the company personnel so the amount of additional time required to complete the manual disconnection of this facility during a service outage could also be reduced.[96]

The Judge recommended generally that there should be neither a universal obligation to provide interconnections at primary feeders nor a universal bar to them. He recommended further that the company should minimize outages at feeders and evaluate the loading on transformers and the short circuit duty limitations at substations in the same manner as it would when serving or attaching new firm load.

Con Edison disagrees only with the Administrative Law Judge's assumption that it needs to evaluate substation short circuit duty limitations when attaching firm *load,* pointing out, correctly, that their sufficiency becomes a matter of concern only when additional *power* enters the

[96]S.M. 2925-2926.

system. The company, portending a disagreement with staff that is discussed *infra,* also observes that improvements to such limitations, to the very limited extent they are possible, could be quite costly.

It appears that the customers who would be interested in interconnecting at primary feeders would be those located in areas served by the company's secondary network who would be interested in exporting power to the company. We generally agree with the Judge, therefore, that we should not unconditionally require the company to interconnect with such customers for the purpose of receiving power from them. We shall, however, adopt that requirement as a general rule from which the company may seek an exemption when such an interconnection would unreasonably interfere with the adequacy and reliability of service to firm customers. As is the case with interconnections at the network itself, we see no need to review every interconnection arrangement, but we shall review any proposed arrangements where the parties cannot agree on safety or cost matters.

Allocated or Non-Network Feeders

Allocated or non-network feeders would directly connect on-site generators to substations without serving the secondary distribution network. Con Edison does not oppose interconnecting with on-site generators at such feeders, but cautions that the costs of doing so could be quite high.

The Judge recommended that Con Edison be directed to proceed, as necessary, with plans to accommodate interconnections at such feeders. He rejected staff's proposal to require the company to allocate existing unused or underused feeders and conduits to on-site generators, observing that the company is prepared to negotiate the provision of such facilities on an arm's length, case-by-case basis. The only comment on this recommendation comes

from Assemblyman Ferris, who requests that we direct the company to inform applicants that they may cooperate with neighboring on-site generators in the construction of allocated feeders. This request, which is supported by staff, appears reasonable and will be adopted.

Interconnections at non-network and allocated feeders would necessarily involve case-by-case arrangements that, once again, need not be reviewed by us unless there are disagreements about their terms and conditions. Accordingly, we shall require the company to provide such interconnections to all customers that are willing to assume their costs. Unlike the Judge, however, we shall extend that requirement to cover existing unused or underused feeders and conduits where interconnections with on-site generators appear both feasible and economical.

Radial System Interconnections

Interconnections to that portion of Con Edison's system that is served by a conventional, radial distribution system are generally possible, and the company does not oppose them. The Judge recommended that an obligation to interconnect at radial distribution circuits be adopted. No party has excepted to this recommendation, which we shall adopt.

COSTS AND CHARGES

General Obligation to Pay Interconnection Costs

Both FERC's regulations implementing PURPA and §66-c of the Public Service Law address the issue of whose obligation it is to assume the costs of interconnections between on-site generators and utilities. FERC allows state commissions a great amount of discretion in setting the charges utilities may impose on on-site generators, requiring only that such charges be "assess[ed] against the qualifying facility on a nondiscriminatory basis with respect to

other customers with similar load characteristics.[97] Perhaps more applicable to Con Edison's situation is FERC's explanation, set forth in the preamble to its regulations, that "the interconnection costs of a facility which is already interconnected with the utility for purposes of sales are limited to any additional expenses incurred by the utility to permit purchases."[98]

Section 66-c of the Public Service Law, which separately obligates utilities to purchase power from, and provide supplemental or back-up power to, on-site generation facilities, states as follows:

> [N]othing contained in this section shall require any such [utility] to construct any additional facilities for such purposes unless such facilities are paid for in full by the owner or operator of the [qualifying] facility.

Taken together, these standards can fairly be read as excusing on-site generators that are new customers from paying for load-related connection costs to the extent such costs are not separately or specially imposed on new firm customers, but that both old and new customers desiring to sell power to utilities must pay the costs that utilities incur to make possible the delivery of the power that the on-site generators contemplate selling. Some parties appeared to believe the costs of increases in distribution capacity that are required solely to accommodate purchases from a customer with on-site generation could not be charged to that customer. This view is incorrect. The contract demand charges included in both the back-up and purchase rate tariffs are designed to recover precisely those costs. When considered with the customer charge, these demand charges would do nor more—but also no less—than recover the costs of connecting a similar-sized firm customer. And §66-c clearly requires that on-site

[97] 18 C.F.R. §306 (a).

[98] 45 C.F.R. 12230 (February 25, 1980).

generators will pay for the additional costs that are directly related to their parallel operations. Thus, Con Edison's and Niagara Mohawk's observation, advanced in their respective Briefs on Exceptions, that an interconnected on-site generator is a different type of customer that imposes costs simply because of the fact of its operating in parallel with a utility is closer to the mark.[99]

A proper interpretation of both FERC's regulations and §66-c provides guidance for resolving one remaining area of disagreement between Con Edison and staff concerning the general obligation of on-site generators to assume interconnection costs. The company excepts to Judge Vernieu's recommendation that a customer be required to pay only a "fair contribution" to the potentially "extraordinary" costs that might be incurred interconnecting it at an allocated feeder, pointing out that both the federal regulations and the state law would clearly mandate payment in full by the customer. Staff, in contrast, contends that other, more general provisions of the Public Service Law might be construed as supporting a contrary interpretation of §66-c. In view of the foregoing discussion, however, it is clear that Con Edison's argument is correct; accordingly, we shall grant its exception. Section 66-c provides no basis for concluding that a utility's other ratepayers should be required to support facilities dedicated to the benefit of only one or a few on-site plants where, as here, the costs of such facilities are over and above the costs of serving firm customers with similar characteristics, are not recovered in other charges, and are incurred solely to enable them to sell power to the utility.

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[99]In this connection, In-Novo requests that a customer with on-site generation who does not operate in parallel with a utility "be deemed as taking conventional service without any interconnection costs." This request, which is not discussed in detail, appears correct as a general principle.

Specific Charges and Conditions

1. *Customer-Related Plant*

Judge Vernieu recommended generally that all separate and identifiable costs of plant, including safety and protective equipment, made necessary because of interconnections between utilities and on-site generators be included in interconnection charges. He specifically excluded metering costs from his recommendation, however, contending that any such incremental costs should be collected in the customer charge imposed on the on-site generator class.

Con Edison excepts, arguing that such metering costs are properly included in interconnection charges. Staff agrees with the company; but the Borough of Manhattan agrees with neither them nor the Judge, arguing that such incremental costs should, instead, be "shared" by all customers, "similar to firm customer treatment."

There is sufficient dissimilarity between the types of metering costs incurred by firm and on-site generating customers both to warrant denying the treatment sought by Manhattan and to support Con Edison's and staff's position. Accordingly, the company's exception will be granted.

2. *Carrying Charge*

Judge Vernieu recommended including in the company's interconnection charges a 9% annual carrying charge to reflect the tax and operation and maintenance expenses associated with such facilities. Manhattan contends, without any empirical support, that this carrying charge should be reduced to 8% to reflect "a reduction in the annual inflation rate." The Borough also requests that it be updated on an annual basis. The request for periodic updating is reasonable, although carrying charges are best

updated within rate cases, not apart from them. Manhattan's exception seeking a reduction in the carrying charges, however, will be denied.

3. *Terms of Payment*

New York City excepts to Judge Vernieu's recommendation against requiring Con Edison to permit one-time interconnection charges to be paid on an installment basis. According to the City:

> In a time of tight money and high interest rates, it is reasonable (and most consistent with federal regulations) to have the utility finance connection charges over a reasonable period of time.[100]

Staff appears to support the City's request, but only for future consideration. RG&E opposes it, arguing that "the thrust of both PURPA §210 and Public Service Law §66-c is that cogeneration facilities must pay their own way."[101]

Although installment payments could presumably reflect interest rates and amortization periods that prevent subsidization of on-site generators, we shall not require utilities and/or their ratepayers to become installment creditors of other businesses. It should be borne in mind that on-site generators will be, for the most part, either profit-seeking, largely unregulated businesses or agencies of government. A potentially profitable on-site generation facility should have little difficulty atracting capital from traditional sources; utilities should not be required to finance those that cannot. Accordingly, New York City's exception will be denied.

4. *Engineering and Feasibility Studies*

Con Edison objects to language in the Recommended Decision suggesting that it may recover, in interconnection

[100]New York City Brief on Exceptions, pp. 11-12.
[101]RG&E Reply Brief on Exceptions, p. 11.

charges, only the costs of engineering and feasibility studies that it would collect from "firm service customers having similar load characteristics."[102] The costs it has in mind, the company explains, would all be related to studies of requests to operate in parallel with the company; firm customers by definition would not be charged such costs, even if their loads were identical, because such costs are not load-related. Con Edison also repeats its request, raised before the Judge,[103] for authority to recover such costs from those customers who apply for service as on-site generators but then do not take it (one reason for which, presumably, being that a company study revealed the infeasibility of such service). No party replied separately to the latter exception.

Manhattan argues that "any feasibility study costs should be borne by the company since they will eventually benefit the entire company. . . ."[104] New York City believes that the first on-site generator to interconnect with the company might end up bearing the costs of examining the matter on a generic basis; the City thus requests that such costs be allocated to all similar on-site generators. The City also requests, with no greater specificity, that we "adopt standards regarding the content of such studies, as well as the length of time within which such studies must be completed."[105]

Staff, discounting the distinction pointed out by Con Edison on exceptions, responds as follows:

> While these studies may be somewhat different and perhaps more extensive than engineering studies for nonparallel operation interconnections, the cost, nevertheless, should not be billed to the on-site

[102]R.D., p. 59.
[103]S.M. 5208.
[104]Manhattan Brief on Exceptions, p. 5
[105]New York City Brief on Exceptions, p. 11. The question of standardization is discussed at pp. 95-97, *infra*.

generator unless similar qualitative engineering and feasibility studies are also billed directly to firm service customers.[106]

Nothing in staff's argument, however, disproves the fact that utilities may be required to undertake feasibility studies solely because on-site generators have requested parallel operations. Nor, therefore, do these arguments provide a basis for relieving the on-site generators of the obligation to pay for them. On the other hand, Con Edison's request that the "similar load characteristics" standard set forth in the Recommended Decision not be read literally has merit. It is difficult to determine whether the Judge actually intended such an interpretation, or whether, instead, he believed that the engineering and feasibility studies discussed here would cover more load-related subject matter than Con Edison contends they do. In either case, the company's exception will be granted to the extent that it concerns the costs of feasibility studies of parallel operations that are distinct from load-related studies performed for firm customers and on-site generating customers alike.

The recovery of such costs from prospective on-site generators that never interconnect is less justified. If, after detailed consideration, such a customer decides it either cannot or will not operate in parallel with the company pursuant to the terms and conditions of the latter's tariff—particularly if the operations would not be feasible from the standpoint of maintaining system reliability—all customers of the company are likely to be better off. (If, on the other hand, the interconnection takes place, the bulk of the short-term benefits are, by federal and state mandates, flowed through to the on-site generator.) Accordingly, we shall require that the costs of studying potential interconnections that never come to fruition be recovered from all ratepayers as a common cost.

[106]Staff Reply Brief on Exceptions, p. 7.

5. *Distribution System Reinforcement*

Con Edison and staff disagree, again, about the extent to which the "similar load characteristics" standard employed by the Judge to resolve interconnection issues applies to the company's proposal to recover in interconnection charges the cost of certain reinforcements to its distribution system. Specifically, the company contends on exceptions that reinforcements to substation short circuit capabilities and transformers may be necessitated solely by the fact of an on-site generator's interconnection; and it offers to specify the relationships between parallel operations and such reinforcements in its proposed tariffs, if we would prefer it. Staff concedes the validity of the company's contention insofar as substation short circuit capabilities are concerned; it is less willing to agree that transformers may also be affected solely because a new power source is introduced.

We recognize that there may be certain kinds of improvements to the distribution system that are required solely to permit parallel operations by on-site generators, but whose costs are not recovered in the contract demand charges they pay. We shall, therefore, grant Con Edison's exception to the extent that it seeks to impose on on-site generators the costs specifically incurred to permit parallel operations. We shall not, however, authorize the company to specify in its tariff the distribution system reinforcement costs it anticipates it could incur solely by virtue of parallel operations. The combination of interconnection costs reflected in charges will probably vary greatly between customers; distribution reinforcement costs in particular may vary the most. To the extent that case-by-case arrangements are required, we will leave it up to the company to raise the claim that such costs will be incurred and should be compensated for. If an agreement between the company and an on-site generator cannot be reached, we will then resolve the dispute.

6. *Standard Costs and Requirements*

The Judge recommended that "Con Edison should be directed to propose for adoption standard interconnection requirements and cost responsibilities for the various types of equipment, sizes and configurations of on-site generators."[107] Arguing that the recommendation is entirely too broad, the company excepts.

The company observes, at the outset, that its proposed tariff already contains a number of provisions concerning standard operation and maintenance procedures for parallel operation, including the following:

1. Maintenance of proper voltage levels and frequency.

2. Putting voltage changes into effect from time to time.

3. Phasing and synchronizing an on-site generator's production with the company's.

4. Taking feeders out of service for maintenance and emergencies.

5. Controlling the flow of real and reactive power.

The company adds that it will propose to include such other conditions for parallel operation as may be approved here. Beyond that point, however, the company contends that it is both unfair and impossible for it to formulate what would essentially be industry standards, acting on its own and at the present time. The company will continue to perform additional research and development related to the feasibility of interconnecting on-site

[107]R.D., p. 58.

generators at its secondary network, as staff recommended;[108] but, the company observes, the very fact that research and development is required suggests that not enough is known about interconnected operations in various circumstances. Accordingly, the company requests that it not be required to do any more than it already proposes to do to formulate standard requirements.

Staff does not oppose the company's exception; indeed, the exception finds a great deal of support in the testimony of staff's electrical engineering witness, who testified as follows:

Q. Do you feel that any decentralized generating facility can be interconnected without specific systems studies?

A. I would recommend that no potential generating facility, regardless of its size, be interconnected without first having been analyzed by the company to determine its compatibility with the existing distribution system. It is impossible to stipulate universal acceptability of any particular decentralized generating facility because of the variability of network-specific criteria. Furthermore, until such time as experience has been gained with

[108]Staff's recommendation, which the Administrative Law Judge adopted and to which the company does not except, is as follows (S.M. 2925):

> The company should continue its research and development efforts similar to the Bronx Frontier Development Corporation's windmill interconnection to explore future possibilities for interconnections to the secondary grid. These research projects will likely be of a size to be practically considered for direct interconnection at the network grid. When sufficient interest in network grid interconnections is shown by the customers, research funding, rather than private funding, should be used to further explore the possibilities and limitations unique to this method of interconnection. These funds may come from the company's existing R&D outlays or specific grants from [the federal Department of Energy].

specific cases, it would not be prudent to obligate the company to automatically accommodate all installations of a certain type since their cumulative impact could result in a degradation of the company's service quality. It would also be unfair to the potential decentralized generation customer to be falsely misled into thinking that his installation could be accommodated on a long-term basis where specific studies might have shown potentially unacceptable operation of the company's network in the vicinity of his generator.[109]

Our discussion of the various interconnection issues before us suggests that a number of costs, including those related to protective equipment, carrying costs, studies and system improvements, most likely will vary from site to site. That being the case, the logical mechanism for fixing costs and most procedures and standards would be a contract. The company has identified some guidelines that should apply in every case, and has proposed to include them in its tariff. As more standards can be formulated, on the basis of operating experience, they too can be incorporated into the tariff. At the present time, however, the record gives little support for the Judge's recommendation that the company develop additional standards. Accordingly, Con Edison's exception will be granted.[110]

Safety-Related Requirements

The Judge adopted the following staff recommendations concerning safety-related requirements:

[109]S.M. 2928. Con Edison did not except to the Administrative Law Judge's apparent adoption of staff's recommendation that it be required to give, in writing, its assessment of the feasibility and approximate costs of a proposed interconnection (R.D., p. 51; S.M. 2929-2930).

[110]This recommendation also pertains to New York City's suggestion, raised in its Brief on Exceptions, that we develop "signal quality standards" in order to "reduce the need for individualized engineering studies."

1. Con Edison should be directed to submit to staff, for its review, publications that will be released to prospective on-site generators regarding design requirements and operating rules and procedures.

2. The company should be directed to submit to staff, for its review, its proposed training program for parallel operation.

3. The company should be permitted to require minimum maintenance standards and schedules for protective, synchronizing and phasing equipment, and also to require periodic certification of compliance with them.

4. The company should be permitted to require customers with on-site generation facilities to locate protective equipment in places that are easily accessible to company personnel at all times, in order to permit rapid disconnection of their generators in emergencies.

No party excepts to these recommendations, which are reasonable and will be adopted.

ISSUES RELATED TO ON-SITE GENERATION IN CON EDISON'S TERRITORY

ESTIMATED EXPOSURE TO ON-SITE GENERATION

The parties to this proceeding devoted much effort to addressing themselves to Con Edison's various contentions that on-site generation is an undesirable technology that is likely, at least in its service area, to be spurred by inequitable public policies and, in turn, to be the source of a number of social problems, including increased usage of

oil and gas, air quality problems and increased retail rates. With respect to each matter, the company seeks either to alter rates for sales and purchases or to deny service outright in order to avoid being a party to these perceived problems. The company contends, quite simply, that the social problems resulting from on-site generation will be severe. Critical to the validity of this contention, however, is the company's own estimate of its potential exposure to on-site generation.

Con Edison initially projected that it was likely to lose 395 customers, representing nearly 1,000 MW of demand, to on-site generation. As noted in the Recommended Decision, however, this projection was made on the basis of several assumptions that, considered together, portrayed the costs of on-site generation as too low relative to the costs of taking utility service. Accordingly, Con Edison later submitted a revised exposure estimate of 159 customers, representing 562 MW of demand and $300 million in annual revenues. The revised estimate still rested on a number of assumptions whose validity staff questioned, as follows:

1. An after-tax rate of return of 15% will be deemed adequate by investors in on-site generation equipment.

2. A property tax assessment rate of 50% will be applied to on-site generation equipment (versus 70% for utility property).

3. The company's retail rates will escalate at the same rate as the price of oil, which, in turn, the company believed would escalate steadily.

4. On-site generators would all rely on diesel combustion generators.

Staff argued that the substitution of more accurate variables into the company's exposure model produces an estimate that only 25 customers, representing 117 MW of load and $61 million in annual revenues, would find on-site generation to be economically attractive. Staff doubted the adequacy of an after-tax return of 15%,[111] and pointed out that a more realistic cost of capital of 20% would discourage investment in most of the on-site generation projects identified by the company. Staff also disagrees with the company's assumed rate of escalation in retail rates, and it questions the lack of evidence about when, and at what rate, customers are expected to leave the system.

The Judge did not squarely address the criticisms raised by staff, observing only that staff itself had employed a 15% return requirement in one of its analyses and that, in another, it had employed what he thought was an exposure estimate of 2,180 MW. Accordingly, he concluded that Con Edison's revised estimate was "reasonable, if not conservative."[112]

Staff excepts, pointing out that it neither employed a 15% return requirement for purposes of developing its own estimates nor submitted an exposure estimate of 2,180 MW. Instead, staff contends, both figures were employed by its witnesses solely for purposes of illustration. Another illustration, and one that staff believes is more realistic, is that Con Edison's model produces a much lower exposure estimate, if it is assumed that (1) investors in on-site generation facilities require a return of 18%, and (2) half of them anticipate that Con Edison's electric rates will escalate no more quickly than they have

[111]Staff observes that the 15% return was presented on the record at a time when "Aaa" rated utility bonds yielded 9.7%. Currently, such bonds themselves yield about 15%.

[112]R.D., p. 105. As will be seen, however, the Administrative Law Judge adopted none of the other conclusions Con Edison believed should flow from this finding.

in the past (*i.e.*, they will not escalate as rapidly as Con Edison once expected the price of oil to increase).

Con Edison defends the 15% return as reasonable, having been arrived at after consultations with interested potential investors in and lenders to on-site generation facilities. It is a return that is consistent with a three-year to six-year payback period, which is, according to the company, the financial criterion about which those investors and lenders are most interested. In any event, the company continues, the 15% return is supposed to be adequate over the long run, and it is not correct to compare it to temporary fluctuations in market interest rates, as it contends staff has done. The company also criticizes staff's illustrative exposure estimate, based as it is on a return requirement that was supported by no witness; but it contends, on the other hand, that the 2,180 MW figure included in staff's evidence was in fact part of a market potential study and should, therefore, be considered a valid exposure estimate.

Were it not for the fact, noted earlier, that Con Edison relied heavily on its estimated exposure to on-site generation when raising several of the arguments next discussed, the matter could be addressed simply as one of a difference of opinions. But some resolution of it is required. The most limited, and probably the only certain, conclusion we can reach on the basis of this record is that Con Edison's inaccurate assumptions about capital costs and oil costs have led it—or rather, its model—to predict a higher level of exposure and a much faster rate of departure from its system than appears likely.

Staff's illustrative power estimate, set forth in its Brief on Exceptions, adapted the company's model to a higher return requirement and a lower electric rate escalation factor. While the company is correct that no witness testified that either revised variable was the proper one to employ in the model as specified, we can conclude, nevertheless, that adjustments in the same direction as staff's to the corresponding variables employed by the company, while holding all other variables equal, would be correct in light

of events to which we have given recognition in recent rate cases. First, we have observed that recent real interest rates—that is, nominal rates less the rate of inflation—"are unquestionably the highest in decades."[113] This condition has persisted since we made that observation. Second, we have, on three recent occasions, reduced the forecasted oil prices employed in companies' revenue requirement computations, in light of the significant slowing in the rate of escalation of oil prices.[114] This trend has continued; indeed, the prices of certain kinds of petroleum boiler fuel have declined.

Thus, some higher rate of return—not necessarily 18%—could properly be employed in Con Edison's model. And, if the company's assumption that customers' expectations of future electric rate increases are tied to expected oil price increases is valid, then expectations now are surely lower than before. Either of these factors separately, or both together, would, if employed in the company's model, produce a lower exposure estimate. Accordingly, even if the company's estimate derived from that model may have once appeared "conservative," there is now reason to believe that it is overstated. Staff's exception to the Judge's acceptance of it is, therefore, well taken.

Con Edison also contends that the Judge gave insufficient weight to the effect that the availability and amount of rates for purchases from qualifying facilities might have on its exposure to on-site generation. According to the company, both its and staff's witnesses analyzed the

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[113]Case 27881, *Continental Telephone Company of Upstate New York, Inc.—Telephone Rates*, Opinion No. 81-17 (issued October 13, 1981), at mimeo p. 25.

[114]Case 27877, *Consolidated Edison Company of New York, Inc.—Steam Rates*, Opinion No. 81-16 (issued October 8, 1981), at mimeo p. 18; Case 27909, *Orange and Rockland Utilities, Inc.—Electric Rates*, Opinion No. 81-24 (issued December 1, 1981), at mimeo p. 27; Case 27984, *Niagara Mohawk Power Corporation—Electric Rates*, Opinion No. 82-4 (issued March 8, 1982), at mimeo pp. 53-54.

potential on-site generator's decision about whether to construct a facility as one of weighing the relative costs of self-supply and utility service. Purchase rates effectively defray the costs of self-supply, the company continues, thereby increasing the potential return on on-site generation investment. Thus, the company concludes, the Judge's observation that purchase rates (as well as back-up and supplementary rates) will have less effect than firm rates on the number of customers electing to invest in some form of on-site generation is unsupported by the record.

Staff agrees in principle that the availability of purchase rates might influence some customers to invest in on-site generation, but it points out, correctly, that Con Edison's studies show that its greatest potential for exposure is among customers who are served by the company's secondary distribution network, most of whom, as explained earlier, very likely will not be able to sell power to the company. Thus, there is no basis for concluding that the Judge erred by considering the impact of retail rates alone when examining the company's exposure to on-site generation.

FUEL USAGE

1. *The Parties' Arguments*

One of the positions taken by Con Edison in this proceeding is, in the words of the Judge, that we should "deny the benefits of PURPA to any prospective [on-site generator] in New York City that would use oil or gas unless that applicant can demonstrate that the oil and gas it will consume *over its lifetime* is less than the oil and gas that would otherwise be consumed in the absence of the facility."[115] The Judge rejected this position, concluding that the evidence sufficiently demonstrates that on-site generation will produce a net savings in oil consumption until the middle of the next decade (after which time the outlook is less clear), and, in turn, that the encouragement of on-site generation would not be inconsistent with state and federal energy policies. He also found no reason to believe that the widespread development of on-site generation would, by itself, lead to a deferral or cancellation of oil-to-coal conversions at utility power plants.

[115] R.D., p. 73, emphasis supplied.

Con Edison excepts, arguing that we should adopt a policy that rate levels to cogenerators should be influenced by oil use considerations. The company contends, generally, that the Recommended Decision, if adopted, would not sufficiently discourage oil consumption, and it renews its request, raised in an earlier motion, to re-open the hearings in this proceeding to receive evidence concerning the impact on oil usage of widespread on-site generation. The company also claims that its evidentiary presentation in the most recent State Energy Master Planning (SEMP) proceedings, reproduced in part in its Brief on Exceptions, demonstrates that on-site generation will lead to an increase in oil consumption by the middle of this decade.

Staff and OCER have replied to Con Edison. Staff points out that there are at least three legal and policy impediments to the adoption of the company's position:

1. FERC's regulations do not (any longer) recognize any distinctions between, on the one hand, oil and gas-fired qualifying facilities and, on the other hand, all other types of qualifying facilities in terms of mandating the availability of nondiscriminatory sales and purchase rates.

2. The efficiency standards set forth in FERC's regulations that are specially applicable to such qualifying facilities[116] require them to use oil more efficiently than does Con Edison itself.

3. Section 66-c of the Public Service Law generally encourages the development of gas-fired cogeneration, without any limitations on the amount of fuel consumed.

[116] 18 C.F.R. §292.205.

Staff also questions the probative value of the company's SEMP proceeding evidence, pointing out the following areas of uncertainty and shortcomings:

1. The company's analysis assumes the availability of an excessive amount of Canadian hydroelectric power for the present, and it ignores anticipated future availability problems by limiting the period for which it has made projections to ten years.

2. It is unclear whether the company assumed the availability of upstate power sources without properly modelling power flows and transmission constraints.

3. The company assumes it will lose 600 MW of load to on-site generation—more than the 562 MW maximum estimate presented in this proceeding—and it assumes also that all the on-site generation will be in place by this year.

4. The pace of oil-to-coal conversions assumed by the company is more rapid than that actually achieved thus far.

5. The analysis does not appear to take into account that cogeneration facilities in office buildings will operate at their highest levels during peak hours, when the thermal output is required for air conditioning. The company's marginal production during those periods is oil-fired.

OCER adds that there is no need to reopen this proceeding to consider the fuel use implications of on-site generation, for Congress, by enacting PURPA, already has made what is for it the requisite finding that on-site generation by qualifying facilities has favorable implications on fuel usage. And OCER points out that the

amount of oil-burning on the margin that is displaced by decentralized generation—if any—is irrelevant: PURPA applies to all regulated utilities, including those in the Midwestern and Rocky Mountain regions that have little or no oil on the margin. OCER argues, finally, that the company's evidence from the SEMP proceeding, and its concomitant request to reflect fuel use considerations in the rates charged or paid to on-site generators, could have been presented earlier in this proceeding than in its Brief on Exceptions.

2. *Discussion*

One of several distinctions between the federal and state laws governing on-site generation is their respective treatments of cogeneration facilities that burn oil and gas. Such cogeneration facilities are generally eligible, under federal law, for avoided-cost-based purchase rates and nondiscriminatory sales rates either if their installation began on or before March 13, 1980 or, if installation began later, they meet certain efficiency standards prescribed by FERC.[117] Oil-fired cogeneration facilities meeting the foregoing criterion are also eligible for the 6¢/kWh minimum purchase price fixed by Public Service Law §66-c if they commenced operations before June 26, 1980, but only to the extent that they do not increase their consumption of oil. The state law imposes neither efficiency standards nor usage limitations on gas-fired cogeneration.

Table 1, *infra*, summarizes the possible combinations of gas and oil-fired cogeneration facilities and their respective eligibility for nondiscriminatory sale and purchase

[117] Qualifying facilities whose construction began before November 9, 1978 need not be paid purchase rates equal to a utility's avoided costs, but only if the state commission regulating that utility finds that a lower rate is "sufficient to encourage cogeneration and small power production." 18 C.F.R. §292.304(b) (3). No party has contended that such a finding is warranted in this case.

rates. The basic conclusion to be drawn from the table is that we are constrained, by either federal or state law, or both, to require the availability of nondiscriminatory purchase and sale rates to all facilities to which they apply. A distinction is made between the purchase rates paid to new oil-fired qualifying facilities and new gas-fired ones, to be sure, but that distinction is mandated by state law and not prohibited by federal law.

TABLE 1

ELIGIBILITY OF GAS AND OIL-FIRED COGENERATION FACILITIES FOR SALE AND PURCHASE RATE BENEFITS UNDER FEDERAL AND STATE LAW

Fuel	Fuel-Use Standard Met:		Eligibility Purchase Rates Established By:		Eligibility For Nondiscriminatory Sales Rates Required By:	
	Federal Efficiency	State Consumption	PURPA	PSL[118]	PURPA	PSL[118]
OIL:	Yes	Yes	Yes	Yes	Yes	Yes
	Yes	No	Yes	No	Yes	No
	No	Yes	No	Yes	No	Yes
	No	No	No	No	No	No
GAS:	Yes	—	Yes	Yes	Yes	Yes
	No	—	No	Yes	No	Yes

It is only for nonqualifying facilities that we are not required to set purchase rates. A fair reading of all the provisions of the Public Service Law suggests that we are not even permitted to set rates for purchases from such facilities unless we first regulate them as utilities; and even then the possibility of invading FERC's jurisdiction may arise. The federal and state on-site generation laws also do not require us to set nondiscriminatory rates for sales to

[118]Section 66-c.

nonqualifying facilities, although we have concluded elsewhere that §65 of the Public Service Law, which prohibits undue discrimination in ratemaking generally, requires the availability to on-site generators of back-up and supplementary rates on a nondiscriminatory basis. And the elimination of the company's existing back-up service classification (SC-3), which no party opposes, effectively guarantees that all on-site generators on Con Edison's system be provided firm service for at least portions of their loads.

Stated simply, Con Edison's exceptions assume a degree of discretion on our part that is greater than that provided by the applicable federal and state on-site generation laws. Accordingly, the company's exceptions will be denied to the extent that they are submitted in support of differential ratemaking on the basis of fuel usage that is not already required by those laws.

AIR QUALITY

A major part of Con Edison's attack on the development of on-site generation in its service area is its claim that it will lead to serious air quality problems in certain areas of New York City. Basically, Con Edison contends that it is incumbent upon us to limit the development of diesel engine facilities by excluding them from eligibility to take service or sell power under the tariffs under consideration in this case. The company's argument follows this line of reasoning:

1. The various rates under consideration will, if approved, spur the development of on-site generation.

2. More than a few on-site generators will use diesel engine equipment.

3. If enough of them are concentrated in particular sections of New York City, there will be a violation of air quality standards for nitrogen dioxide.

4. Thus, the rates under consideration will lead to a violation of air quality standards.

5. Under the assumption that no other agency—state, local or federal—will act to prevent or eliminate such a violation, it accordingly is *our* duty to hinder the development of diesel engine on-site generation.

A finding that there will be a violation of air quality standards for nitrogen dioxide requires complete acceptance of the company's estimate of its potential exposure to diesel-fired on-site generation. Even then, however, the violation indicated by the company's model affects an area of only one-quarter square kilometer, and staff demonstrated that it could be "abated" simply by removing from the data base three on-site generators with relatively low exhaust stacks. In other words, the adverse environmental impacts portrayed in the company's "worst case" analysis are sensitive both to the number of on-site generators and to their operating configurations. A change in either input would change the result suggested by the analysis. Thus, the Judge was less concerned than the company about the likelihood of a violation occurring.

Judge Vernieu also declined to accept Con Edison's contention that the State Department of Environmental Conservation (DEC), New York City's Department of Environmental Protection (DEP) and the federal Environmental Protection Agency (EPA) all are unprepared or unwilling to prevent on-site generators from violating the applicable air quality standards. DEC, he noted, has been effectively apprised of the air quality implications of on-site generation and is currently engaged in the process

of modifying the state implementation plan[119] accordingly. That no modifications have been forthcoming thus far is understandable, he reasoned, because it is unclear at this time how many on-site generators there will be, much less what types and levels of emissions can be expected from them. Moreover, he noted, DEP not only has the authority to require emissions monitoring, but also has exercised that authority in the case of an on-site generator in midtown Manhattan.

The Judge observed further that FERC has undertaken to keep track of both the market penetration by diesel and dual-fuel on-site generation facilities and the pace at which such facilities are seeking qualifying status, and to make its compilation available to the national and regional offices of EPA and state and local air quality regulatory agencies. He also apparently believed that FERC would keep track of the emissions levels from qualifying facilities. And he noted that FERC found that the operation of all qualifying facilities projected for the New York City area would not violate nitrogen dioxide standards and would not consume the remaining cushion that now exists for absorbing additional nitrogen dioxide.

In summary, Judge Vernieu concluded that emissions from on-site generators would be reported and kept track of, and that Con Edison could—and should—present its claimed potential for violations to enforcement agencies (*e.g.*, EPA and DEC). And he found, contrary to the company's claims, that those agencies "have not in the past nor are they now failing or refusing to perform their duties."[120] Accordingly, he refused to deny the availability of nondiscriminatory purchase and sales rates to facilities with diesel engines.

Con Edison excepts, arguing that it was improper for the Judge simply to assume the elimination of three

[119] The state implementation plan is the program under which the state sets standards that will insure compliance with those set forth in or established under the federal Clean Air Act.

[120] R.D., p. 90.

sources of emissions from its air quality study, as staff had done, in view of his finding that the company's exposure estimate was reasonable. The main thrust of the company's exceptions, however, is directed at the Judge's conclusion that the state, local and federal air quality regulatory agencies have not been remiss in thier handling of potential air quality problems associated with on-site generation.

With respect to DEC, Con Edison notes that Part 201 of its regulations currently exempts from permit requirements fuel burning equipment using diesel or Number 2 fuel oil or natural gas. Thus, the company points out, under the existing regulations information on the individual or cumulative air quality impacts of diesel-fired on-site generation will not be compiled. The company concedes that DEC has evinced an awareness of the potential for air quality problems, but it emphasizes that no action has been taken up to this time; and it believes that there is also some uncertainty about whether small boilers still might be exempted from the operation of the revised regulations. These uncertainties about whether, when and to what extent DEC will promulgate regulations governing on-site generators' emissions provide, in Con Edison's view, sufficient reason for having us "exercise [our] responsibility as a steward of the State's air resources at least until DEC amends the [state implementation plan] and its licensing regulations."[121]

While acknowledging the New York City DEP's authority to license on-site generators, the company faults that agency for failing to act on its (the company's) request, filed on November 1, 1978—that is, eight days before the enactment PURPA and sixteen months before the issuance of FERC's regulations governing on-site generation rates and practices—to "conduct a generic environmental impact analysis of the effects of conversions from central station steam and electric generation to on-site steam and electric generation."[122] The request was

[121] Con Edison Brief on Exceptions, p. 63.
[122] *Id.*, p. 64.

denied on November 28, 1978; according to the company, that denial and DEP's failure yet to act makes it "likely that such an investigation will never be undertaken."[123]

Turning next to EPA, Con Edison concedes that on-site generators are subject to that agency's prevention of significant deterioration (PSD) regulations applicable to pollution sources located within areas whose air quality meets the Clean Air Act's national ambient air quality standards. Those regulations require a review of any proposed facility whose operation may result in a significant net increase in emissions of any pollutant that is regulated under the Clean Air Act. In order to obtain a construction permit, the facility's building must present, among other things, a best available control technology (BACT) analysis to demonstrate both that applicable air quality standards have been complied with and that the most effective known emissions control techniques have been applied. The main problem, as Con Edison views it, is that "there is no assurance that the owners of these facilities will apply to EPA for a PSD permit."[124] Were diesel on-site generation equipment subject to DEC permit requirements, the company argues, it would be reasonable to assume that issuance of DEC's permit would be conditioned upon obtaining a PSD permit from EPA. Moreover, although DEP does have licensing authority, the company continues, there is "no evidence" that DEP will require an on-site generator to obtain a PSD permit.

Con Edison sees as an additional problem the absence of EPA guidelines setting forth BACT standards for nitrogen oxide emissions from stationary diesel engines, adding that "[i]n point of fact, there is no viable control technology to reduce significantly No^x emissions from such engines."[125] Thus, in the company's view, even if PSD permits are obtained by on-site generators, it is not certain that nitrogen dioxide impacts will be significantly

[123] *Id.*, p. 65.
[124] Con Edison Brief on Exceptions, p. 65.
[125] *Id.*, p. 66.

mitigated, because the emissions from individual sites, considered separately, might not violate national standards. Accordingly, the company concludes, "[t]he lack of a programmatic or generic environmental impact assessment to address cumulative impacts from prospective [on-site generation] facilities would result in EPA continuing to issue PSD permits. . .[until] No_2 levels would be permitted to rise up to the standard which would inhibit further growth in the City."[126]

Con Edison argues, finally, that the Judge's reliance on the existence of a FERC program to keep track of the market penetration of diesel and dual-fuel qualifying facilities was "entirely misplaced," for FERC has not, contrary to his assertion in the Recommended Decision, required facilities applying for qualifying status to submit emissions data. On this latter point, the company is correct; but it is also correct that, as noted, FERC does plan to keep track of the number of facilities and report that information to various air quality control agencies.

The only other parties to raise objections to Judge Vernieu's refusal to treat diesel-engine on-site generation facilities differently from other such facilities for ratemaking purposes are the Borough of Manhattan and New York City. Manhattan states that it "cannot totally agree" with that decision, but it recommends only that we delay the effective date of the rates adopted in this case for 120 days in order to permit the Borough to seek the New York City Council's passage of an on-site generator licensing law. New York City, on the other hand, believes that we could require a state environmental quality review "or similar environmental assessment" from any on-site generator whose facility's capacity exceeds 1,000 kW.

Staff, responding to Con Edison, contends that the company's analysis indicating a geographically limited violation of the air quality standard for nitrogen dioxide emissions is a "worst case" analysis in which it is assumed

[126] *Id.*, pp. 66-67.

that 141 on-site generators (out of a projected total of 159) begin operations simultaneously. Considered in this context, staff's "abatement" of the violation by removing three sources from the data base is far less unreasonable than Con Edison depicts it to be.

Staff also defends the performance of the various agencies the company criticized in its Brief on Exceptions, agreeing with the Judge that (1) DEC is in the process of amending Part 201 of its regulations; (2) DEP has exercised its authority to review and impose conditions on the operations of proposed on-site generation facilities; and (3) FERC has undertaken to compile information on certain types of facilities. And staff points out that Con Edison has not denied that EPA will monitor PSD permits, but has, instead, merely alleged that there are no assurances that prospective on-site generators will comply with the law by applying for permits. Such an allegation provides, in staff's view, scant basis for restricting the applicability of on-site generation rates.

In resolving this issue, three considerations should be borne in mind. First, the likelihood that a violation of air quality standards for nitrogen dioxide emissions will occur is completely dependent upon the likelihood that Con Edison's estimated exposure to on-site generation will materialize. We have already concluded that a far lower level and slower rate of exposure is likely.

Secondly, FERC, having specifically examined the potential impacts of diesel and dual-fuel on-site generation in the New York City area, concluded as follows:

> [T]he [Final Environmental Impact Statement] concluded that no significant effect on air quality will occur in the New York City area and that the operation of all cogeneration facilities projected for this area would not violate nitrogen dioxide standards and would not consume the available increment of nitrogen dioxide.

> The Commission believes that it is the ability cogenerators have to avoid municipal taxes, and not the rates available to them under PURPA, which is the primary force behind the development of diesel and dual-fuel co-generation in New York City.[127]

FERC found, and we agree, that the adoption of non-discriminatory rates for on-site generators will not necessarily cause a violation of ambient air quality standards. And even if diesel-fired on-site generators that commence operations after we issue this decision do consume a portion of the available increment of nitrogen dioxide, other agencies are responsible for determining the "best" manner in which it should be consumed.

Thirdly, authority to regulate the operations of individual on-site generation facilities is actually very limited: such facilities, like any other non-utility industrial facility, are not regulated by us. Our regulatory powers that are required to enable sales of power by them to utilities are all directed to the utilities' side of those transactions.[128] Section 66-c of the Public Service Law emphatically makes this point.[129] Subdivision one of that section confers no authority on us to regulate the compliance of individual onsite generating facilities with applicable environmental standards, while subdivision two, which concerns utility on-site generation subsidiaries, provides as follows:

> Any such subsidiary corporation shall be exempt from any regulation by the commission under this chapter and the commission shall have no authority to regulate any rates, charges, service terms or service practices relating to any electricity, gas or steam produced by any such subsidiary corporation at any such facility except as specifically provided in subdivision one of this section.

[127] 46 F.R. 33026 (June 26, 1981).

[128] Conversely, such facilities do not appear to be exempt from any laws and regulations of general applicability to non-utility industries simply because they happen to sell electric power.

[129] This section would, of course, only apply to gas cogenerators using oil as their back-up fuel, as it pertains to the air quality issue raised by Con Edison.

Since §66-c(1) confers no authority on us to adopt rates that are discriminatory with respect to ownership status, it follows that the legislature has not authorized us to regulate either utility-owned or independent facilities, either directly or indirectly through ratemaking mechanisms, on environmental grounds.

The circumstances presented where a utility provides service to an on-site generator are similar to those presented where a utility sells power to any other industrial plant. By selling power, the utility enables the plant to operate and, thus, to pollute the environment if the plant fails to comply with applicable laws and regulations. It surely cannot be true that, under these circumstances, we would be free to impose a discriminatory rate for electric service to the plant as a means of discouraging it from polluting. PURPA and the Public Service Law allow us to regulate on-site generation rates and interconnection standards, but there is no basis for the contention, underlying Con Edison's and New York City's positions, that by virtue of these laws we have greater authority over on-site generators than we have over that hypothetical plant.

In short, the rates approved here will not, in and of themselves, necessarily engender a particular response by any on-site generator. Complying with applicable statutes and regulations governing environmental protection is not in any manner inconsistent with taking the fullest advantage of those rates, except to the extent that any type of enterprise—not simply a producer of electric power—might attempt to maximize profits by not incurring compliance

costs. Under PURPA and the Public Service Law, neither utilities nor commissions are authorized to set discriminatory rates on the basis of a bald presumption that certain types of qualifying facilities are more likely than others not to comply with environmental protection laws. Accordingly, Con Edison's exceptions will be denied.

Although we have decided not to discriminate among individual facilities on the basis that some of them might adversely affect the environment, we have been mindful, throughout this proceeding, of our responsibility, arising from the State Environmental Quality Review Act (SEQRA), to investigate the potential environmental impacts of our actions and to weigh the ensuing costs and benefits of those actions. To this end, we instructed the parties to present evidence on the potential environmental impacts of on-site generation in Con Edison's service territory.[130] Staff and the company presented their environmental assessments in their respective testimonies. As discussed above, we have considered this evidence in reaching our decision. We have found that there likely will be increases in nitrogen oxide emissions, but that such increases will not violate ambient air quality standards. We have also concluded, in any event, that we do not have the authority to decide how the remaining air quality cushion will be consumed. We have decided, however, to alert the environmental agencies that do have that authority to this potential problem, and to urge them to monitor the situation and take whatever action is necessary to prevent air quality problems. On the benefit side, we have found no basis for disturbing Judge Vernieu's conclusion that oil consumption for the near-term future will be reduced by the operations of on-site generation facilities; and we also have determined that their operations might enable utilities to avoid capital investments in new capacity. We find, therefore, that the potential environmental costs of

[130]*Order Adopting Recommended Interim Decision*, issued February 11, 1980.

on-site generation are outweighed by the potential benefits.

We shall also deny New York City's exceptions, for it falls within DEC's authority, not ours, to require individual on-site generators to file environmental impact analyses. Finally, we shall deny Manhattan's exception. This proceeding has been underway for nearly three years, and the New York City Council has had ample time to approve the legislation Manhattan seeks. Any additional delay on this account would be unwarranted.

TAXATION

Throughout this proceeding, Con Edison has maintained that on-site generation in its service territory appears economically feasible only because the company's retail rates include allowances for state and local taxes and other costs to which the on-site generators are not subject.[131] The company explained:

> As matters now stand, the decision of [a] SC 4 or SC 9 customer on whether or not to become a cogenerator is affected by distorted price or cost comparisons. To begin with, the potential cogenerator is now paying rates under SC 4 and 9 which are more than the marginal costs incurred by the Company in supplying them with service. Any cogeneration induced because these rates are more than the Company's marginal costs would occasion an inefficient allocation of resources.
>
> The probability of an inefficient allocation of resources is further increased because the costs of cogeneration perceived by the potential cogenerator do not internalize pollution costs to the same extent that those costs have been internalized by the Company and do not reflect the same burden of

[131]As noted earlier, FERC apparently agrees with this contention.

> state and local taxes that is borne by the Company. What this means is that the potential cogenerator is comparing a cost of cogeneration which is too low in terms of actual resource utilization with a cost of Company generation which is too high in terms of such resource utilization. A decision to cogenerate that is induced by such a comparison cannot be justified by principles of economic efficiency or the efficient utilization of society's resources.[132]

In light of these considerations, Con Edison contended as follows:

> [I]n terms of the goal of an efficient utilization of society's resources, we would be justified in urging that no Company services should be supplied to cogenerators because cogeneration is the creature of discriminatory tax and environmental legislation and regulations and is necessarily counter-productive in terms of resource utilization. That being so, our rate proposals are *a fortiori* justified from the standpoint of efficient resource allocation.[133]

The rate proposals to which the company alludes include stringent contractual charges for sales to on-site generators and rates set at 85% of avoided costs for purchases from them. It will be recalled from various discussions earlier in this Opinion that the discriminatory aspects of these proposals do not comport with federal and state standards governing rates for sales to and purchases from on-site generators, and that other aspects of them are less sound as a matter of policy, than are the rates we have adopted. Con Edison, moreover, admits that it has failed to provide a measurable link between, on the one hand, the different tax and regulatory burdens borne by it and on-site generators, and, on the other hand, the specific

[132]Con Edison Brief on Exceptions, pp. 36-39.
[133]*Id.*, p. 39.

rates it proposed.[134] Accordingly, there are no evidentiary or policy justifications for adjusting the rates adopted in this proceeding to reflect those burdens.

Con Edison is correct in pointing out that the Judge erred when he asserted that the company sought *only* our assistance in seeking legislative changes to its tax burdens;[135] however, that may be the only assistance we can provide. At the bottom of the company's complaint is the fact that, as noted by the Judge, and on-site generator is able to internalize certain transactions which, if made between two parties, would be subject to excise taxation. This advantage is not unique to on-site generators: any person that makes his or her own goods from raw materials instead of purchasing them can frequently avoid paying several "layers" of taxes (although not necessarily excise taxes) as well as other kinds of costs. No seller of finished goods in a competitive marketplace could seriously consider charging prices for finished goods to buyers that differ according to whether those buyers purchase all or only some of their requirements from the seller. Con Edison's proposal to differentiate its rates is credible only because it would have sufficient market power to enforce the distinction, and not because it has been subjected to a qualitatively unique tax burden.

We can do no more than agree with the company that legislative relief from the tax laws it cites may have the effect of slowing the development of on-site generation; and we are mindful that elimination or moderation of those taxes would also benefit those customers who cannot resort to self-supply. However, no adjustment to the rates charged or paid to on-site generators is warranted. The relief the company seeks must come from the legislature.

[134]Con Edison Brief on Exceptions, p. 39.
[135]Thus, the Judge did not specifically reject the company's proposal to adjust on-site generation rates to reflect the effect of taxation on its exposure to on-site generation.

LOST BUSINESS ADJUSTMENT CLAUSE

As part of its proposed rates for sales to on-site generators, Con Edison included a "lost business adjustment clause" (LBAC) that was designed to prevent the development of on-site generation from having an adverse effect on its revenues. Stated simply, the LBAC would allocate the company's estimate of the firm service revenues it has lost to on-site generation (1) primarily, to on-site generators, (2) secondarily, to PASNY delivery service customers and most firm customers, but (3) not at all to the firm customers remaining in the classes from which most on-site generators will come.

Judge Vernieu recommended against adoption of the LBAC, reasoning that its operation would both impermissibly discriminate against on-site generators (and in favor of large customers who could economically develop self-generation but who continued to take firm service for their full requirements) and, as a consequence, encourage on-site generators to install enough capacity to meet their entire requirements and leave the company's system entirely, ultimately forcing smaller firm customers to assume the total burden of lost revenues. On exceptions, however, Con Edison states that it would be willing to implement a LBAC with a more evenhanded impact, although it continues to defend its original proposal as being consistent with FERC's regulations.[136]

The Judge also concluded that Con Edison had failed to demonstrate a need for the LBAC, having presented no evidence to show (1) the rate at which on-site generation would supplant firm service; (2) the likelihood of significant revenue losses in the near term; or (3) its inability to anticipate and recoup such losses in an ordinary rate case. In so reasoning, the Judge appeared to anticipate our decision in the most recent Con Edison steam rate case, in

[136]PASNY points out that to the extent that the LBAC would allocate a portion of lost *production* costs to *delivery* service customers, its operation would not be fair or reasonable to those customers.

which the LBAC contained in the company's tariffs for steam service was discontinued. We stated there:

> It is true that, as the company says, only an automatic adjustment clause can eliminate all uncertainty attendant on a forecast of lost business. Nevertheless . . . the risk of error in estimating the level of lost business no longer is so great that it must be borne by customers if the company is to have a reasonable opportunity of earning a fair return.[137]

Without evidence on the matters specified by the Judge, it would be difficult to demonstrate that the requisite "risk of error in estimating the level of lost business" exists. Accordingly, our decision in the recent steam rate case could conclude this issue against the company.

Con Edison has raised no argument on exceptions that would contradict such a conclusion; indeed, the company contends that adoption of the LBAC is justified because the accuracy of its 562 MW exposure estimate was accepted by the Judge. Orange and Rockland, on the other hand, argues more to the point that adoption of the LBAC would be justified here because there is insufficient experience with serving on-site generators to justify attempting to forecast the level of lost business, much less estimating the risk of error in such a forecast.

Con Edison and staff disagree about the significance of the fact that neither the imminence nor the rate of customer losses was developed on the record. Staff, noting that past conversions have been few in number, argues that the long lead time required by prospective on-site generators to obtain capital financing, fuel supplies and construction and operating permits (including environmental permits) insures that there will be adequate time to develop adjustments for lost business during the course of

[137]Case 27877, *Consolidated Edison Company of New York, Inc.—Steam Rates*, Opinion No. 81-16 (issued October 8, 1981), at mimeo, p. 5.

ordinary rate proceedings, thus obviating an automatic adjustment clause. The company argues, however, that since the incentives to develop on-site generation were fewer in the past than will be the case in the future, staff's reliance on the historic rate of conversions is misplaced. The company also claims that staff's reliance on the long lead times required to convert to on-site generation should be accorded little weight, since staff was apparently unaware of how many such conversions are underway. Staff points out in response that no such information has been provided by the company, either.

As discussed earlier, the validity of Con Edison's 562 MW exposure estimate has been drawn into question, in light of recent trends in capital costs and oil prices, so the risk of economic loss will not be as severe as the company supposes. And although the company has now disclaimed their importance, the principal features of its LBAC proposal—the only one submitted in this proceeding—are too discriminatory to pass muster under either state or federal laws. Finally, the company has made no satisfactory showing that customers' conversions from full requirements firm service to on-site generation will occur so rapidly, and to such an extent, that our usual procedures for recouping revenue shortfalls—ordinarily rate cases—cannot be employed, at least for the time being. Accordingly, Con Edison's exceptions seeking adoption of the LBAC will be denied.

LACK OF RATEPAYER SAVINGS

One of the several arguments advanced by Con Edison in opposition to setting rates for purchases from on-site generation facilities equal to the purchasing utility's avoided costs was that retail customers of that utility would not enjoy any short-term cost or rate decreases as a result of such purchases. Judge Vernieu did not disagree with the company's contention, but he concluded that it

provided no basis for blocking the implementation of those rates.

No party has directly challenged this conclusion, although Orange and Rockland contends generally on exceptions that the impact of such purchases on retail customers "should be a serious consideration in deciding how and how fast to adopt cogeneration procedures."[138] The utility continues: "To the extent that the law provides the Commission with any flexibility as to implementing cogeneration procedures, the Commission should be satisfied that it has done its utmost to avoid substantial adverse customer impact where possible."[139] It is not clear whether Orange and Rockland is suggesting that we let customer impact considerations color our findings about whether and to what extent certain costs are marginal or avoidable, or whether, instead, it is urging only that rates for purchases from or sales to on-site generators not include any non-cost bonuses (except, presumably, to the extent that state law may require a contrary result) nor exclude any costs, respectively.

Boise Cascade points out, in its non-party comments, that retail ratepayers of a utility can realize savings through the utility's purchases from on-site generators, to the extent that those on-site generators elect, under FERC's regulations,[140] to sell power to the utility at a price that is lower than its avoided costs.

There is no reason to disturb either of the Judge's conclusions, for both are essentially correct. Utility purchases from on-site generators at rates equal to avoided costs probably will not lead to short-run ratepayer savings, but it is also true that the potential for such savings is not a prerequisite for authorizing such purchases, even after the *American Electric Power* decision. Orange and Rockland's request, if interpreted to mean that on-site generators should pay for all costs they impose and receive only the

[138]Orange and Rockland Brief on Exceptions, pp. 2-3.
[139]*Id.*, p. 3.
[140]18 C.F.R. §292.301(b)(1).

costs they allow utilities to avoid, has been reflected in this decision, which, in turn, follows the requirements of the applicable federal and state laws.

IMPLEMENTATION FOR OTHER UTILITIES

PROCEDURES

No party proposed, and Judge Vernieu did not recommend, specific procedures or guidelines for incorporating the generic determinations reached in this proceeding into the on-site generation rates of the other electric utilities in the state. The Judge recommended, instead, that the utilities be directed to file proposed rates that are consistent with the generic determinations; these rates would be adopted, possibly with modifications, after a suitable comment period. The only party to comment on this recommendation is the Borough of Manhattan, which, although it is served only by Con Edison, suggests that the other New York State utilities be required to file rate proposals within 60 days after the conclusion of this proceeding in which they "show cause why their proposed rates conform to the new standards."[141] Manhattan does not explain why it is interested in the procedures to be followed by utilities serving other areas of the state.

In view of the different kinds of issues that must be resolved in the process of determining, on the one hand, rates for utility purchases from on-site generators and, on the other hand, rates for utility sales to them, we conclude that these rates should be implemented in two stages, the former fairly quickly, the latter less so.

We shall, accordingly, direct the New York State electric utilities subject to our jurisdiction and PURPA (except, of course, Con Edison), first, to submit, within 60 days after the date of issuance of this decision, proposed purchase rates that conform with the guidelines set forth

[141]Manhattan Brief on Exceptions, p. 7.

in this Opinion and Public Service Law §66-c. These proposals should be in the form of proposed tariff amendments, but they should not be formally filed as tariff amendments. At the same time, also as part of the first stage, the utilities shall similarly submit proposed tariff amendments, as required, to make available to customers with qualifying on-site generation facilities the rates for firm service that are available to the customer classes of which those customers either are members or would be members but for the fact that they operate on-site generation facilities.[142] Each utility's proposals will be issued by the Secretary to interested parties, including prospective on-site generators, located or planning to locate within that utility's service area.[143] The parties will then be allowed 30 days after the date of issuance to comment on the proposals. Depending upon the nature of the comments received, we shall then (1) adopt complete proposals, either as initially proposed or as modified in light of the parties, comments, and on either a permanent or temporary basis; and (2) conduct further proceedings, including, if necessary, formal hearings on those aspects of the proposals we find require further consideration. After rates are adopted pursuant to this first stage, on-site generators will be able to engage in simultaneous purchase and sale transactions under the utilities' tariffs; and to the extent that the utilities' firm service rates reflect time and seasonally-differentiated marginal costs of service, they should also adequately serve, at least for the time being, as substitutes for back-up and supplementary rates.

In the second stage, the utilities will be required either to develop and propose back-up, supplementary and interruptible rates for on-site generators as a separate class or to demonstrate, on the basis of actual load and cost

[142]If interruptible rates are currently available to customers in those classes, they should similarly be made available to on-site generation customers.

[143]Some parties, of course, may be interested in more than one utility's proposals.

data, that such rates should not be offered.[144] Because the development of these rates will require an explication of the utilities' total marginal costs of service, we shall allow them more time to submit their proposals. Specifically, we shall direct each utility to submit its proposal on the earlier of the date it files its next major rate case application (if not sooner than 90 days after the issuance of this Opinion) or six months after the date of issuance of this decision.[145] The proposals will then be issued for comment and subsequently adopted following procedures similar to those adopted for purchase rates.

The utilities will also be authorized to propose, in the second stage, changes to the amount of their purchase rates to reflect any changes in their estimates of marginal costs. And they will not be precluded from submitting evidence supporting changes in the structure of purchase rates and/or withholding from qualifying on-site generators the availability of firm service rates. We would expect, however, that evidence related to the latter issues would include actual load and cost data.

GENERAL FINDINGS AND RECOMMENDATIONS

As we stated when we instituted this proceeding, we intended that the record in this proceeding provide a basis for adopting certain findings and recommendations that can be applied on a statewide basis to on-site generation tariffs. Those findings and recommendations that we shall adopt now, along with those that require further consideration, are next discussed.

Marginal Costs—General

All parties to this proceeding agree that utilities' marginal costs should be employed for purposes of determining avoided costs, which, in turn, determine the rates

[144]*See,* 18 C.F.R. §292.305(b) (2).

[145]Again, these proposals should not be formally filed as tariff amendments, but they should be in that form.

paid by utilities for purchases from on-site generators. Rates for sales to on-site generators should also reflect marginal costs, to the extent that we have already adopted firm service rates based on marginal costs; all parties commenting on the matter, however, agree that rates for sales should be adjusted upward or downward, as required, to recover embedded costs. All of these recommendations will be adopted generically.

Marginal Energy Costs

Most parties agree that a utility's marginal energy cost is its "marginal financial lambda," that is, the average of the New York Power Pool dispatch lambda and the utility's hypothetical internal lambda for any given level of production. Those parties that disagree have raised no arguments sufficient to block adoption of that measure of costs for all utilities.

Staff states that it is possible now to project the marginal financial lambda for other New York utilities using various computer models that simulate future Pool operations. Accordingly, projections of marginal energy costs derived from such models should be implemented at the conclusion of this proceeding.

Avoided Costs

All parties agree that any utility's marginal energy costs are avoidable if power is delivered by on-site generators. For Con Edison, all parties agree that distribution costs cannot be avoided by such deliveries; this conclusion can also be applied to all other utilities, at least as a rebuttal presumption. In the absence of data indicating the contrary, marginal capacity costs that vary with system peak loads can be deemed avoidable if on-site generators deliver power during peak periods.

Rates for Sales—General

Firm service rates must be made available to all on-site generators, unless a utility can demonstrate that offering them would not be justified. While FERC's regulations generally require the availability of back-up, supplementary and interruptible rates, they need not be offered if doing so would be unduly burdensome to a utility. We conclude that offering such rates in the absence of a cost justification therefor would be "unduly burdensome," although the requirement to offer them cannot be waived unless notice and the opportunity for comment has been provided to the utility's customers. Accordingly, utilities should be prepared either to propose such rates or to submit an adequate justification for omitting them. To the extent that interruptible service is available to non-generating customers belonging to the same classes as customers who have or intend to develop on-site generators, it should be made available to the latter customers, provided that they are eligible to continue to take service under firm rates.

Simultaneous purchase and sale arrangements should be made available to all qualifying facilities. Back-up and supplementary rates should also be made available on a non-discriminatory basis to all on-site generators regardless of qualifying status.

Back-Up and Supplementary Rates

The following features that have been adopted for inclusion in Con Edison's tariffs governing sales to on-site generators can also be adopted for other utilities:

1. Maximum load factor standard for back-up service: The 10% load factor limit, for both the summer and winter periods, provides both a sound basis for developing different rates and a reasonable limit on eligibility.

2. Usage-sensitive charges for capacity costs that are related to class and system peak demands: In the absence of load data that clearly support less-variable charges, system peak-related costs should be recovered in peak-period per-kWh or ratcheted per-kW rates, and costs related to class peaks should be recovered in peak-period, ratcheted per-kW rates.

3. Contract demand charges on a per-kW basis will be permitted for the recovery of distribution-related costs that are determined by individual customer peaks.

4. Reactive power charges will be permitted only if they are also imposed on firm customers.

5. The maximum required term for contract demand charges is one year.

The first three conditions can be usefully adopted in the rates developed by other utilities, but they need not be if other conditions appear more proper in light of actual load and cost data. The last two conditions, however, shall be incorporated in all such rates.

Staff and Con Edison agreed that marginal distribution capacity costs should be recovered equally in the as-used and contract demand charges. This assignment of costs was concededly arbitrary, but it can nevertheless be applied to the other utilities on an interim basis, if a more refined assignment of distribution costs cannot be immediately developed. Resolution of this matter may require more detailed consideration for each utility.

Rates for Purchases

Absent an agreement fixing a different rate, qualifying facilities must be paid a price equal to 100% of a utility's

avoided costs for power delivered to that utility, unless, as qualifying facilities under §66-c of the Public Service Law, they must be paid no less than 6¢/kWh. These requirements must be reflected in all utilities' tariffs.

In addition, the following conditions, adopted for inclusion in Con Edison's tariffs, shall be adopted by the other companies:

1. Fixed contractual or variable "as-delivered" rates [must] shall be made available to on-site generators, at their option. In addition, voluntary, negotiated hourly rates will be permitted for larger customers.

2. Neither the payment of capacity credits into escrow accounts nor the requirement of an unduly long notice period (*e.g.*, five years) before discontinuation of deliveries will be permitted.

3. On-site generators shall pay contract demand charges for the distribution capacity required to facilitate utility purchases, to the extent that such capacity exceeds the capacity paid for, as applicable, in firm, back-up, supplementary or interruptible rates.

Wheeling or Delivery Rates

Our jurisdiction in this area is not exclusive, and the two proposals presented here were too unclear to be adopted. No such rates will be required at this time; and none will be adopted until hearings are held.

Interconnection Costs and Standards

On-site generators can be properly charged for the additional costs that the utilities to which they are interconnected incur solely to comply with those customers' requests for parallel operations. Such costs include, but are not necessarily limited to, the following:

1. Metering costs in excess of those incurred to supply firm service to customers.

2. Annual carrying charges on plant required for interconnections, to recover taxes and operation and maintenance expenses.

3. The costs of engineering and feasibility studies and reinforcements to the distribution system that are incurred soley to permit purchases from on-site generators.

Utilities will not be required to offer installment payment plans for interconnection costs. Utilities are free to propose such arrangements if they include compensatory payment terms.

The parties to this proceeding have reached a fair amount of agreement about the general interconnection standards and operating procedures that should be developed for parallel operations; and the other utilities in the state have also submitted interim guidelines. Tariff provisions similar to those approved for Con Edison, as well as the requirement that publications and training programs concerning parallel operations be reviewed by staff, should be proposed by the other companies in their purchase rate tariffs.

Because site-specific interconnection standards and costs may vary greatly, both among companies and among customers of one company, a provision requiring our arbitration of unresolved disagreements between companies and customers should be included in all tariffs.

OTHER MATTERS

Reconsideration of New York Power Pool Pricing

Although the formulation of marginal energy costs recommended by the Judge correctly takes into account the effect of New York Power Pool transactions on utilities' marginal opportunity costs of energy consumption, he expressed concern that his formulation may not be the most economically efficient one:

> [T]he marginal energy cost that appears to be correct for the individual utility is above [system and dispatch] lambdas for buyers and below [dispatch] lambdas for sellers. This suggests that using such a measure for pricing will not maximize the efficiency with which New York's resources are used because it will be too high for buyers and too low for sellers. Whether this requires consideration of the share-the-saving rule or of the Commission's position that the individual utility's marginal energy costs . . . are to be used in rate design is a matter the Commission may desire to consider in further proceedings.[146]

Further consideration of this matter should be reserved for one or more proceedings in which utilities' retail rate designs are fully considered. We have recently concluded proceedings in which the economic effect of Pool transactions has been taken into account in the design of energy rates for five of the seven major companies,[147] and the expeditious implementation of rates for on-site generators that have a similar cost basis is the paramount consideration at this time.

[146] R.D., p. 185.

[147] Niagara Mohawk, Orange and Rockland, Long Island Lighting Company, Rochester Gas and Electric, and New York State Electric & Gas. We shall shortly issue our decision concerning Central Hudson's electric rate design as well.

On-Site Generation and System Planning

Assemblyman Ferris requests, in his Brief on Exceptions, that we "should require feasibility studies to be conducted by Con Edison, in cooperation with the PSC and the Power Authority, to determine how a planned decentralization of the electric system might impact future costs in the service area."[148] This request, however, appears to forget that the "decentralization" that is the subject of this proceeding is—or, rather, will be—a matter that is beyond the purview of either Con Edison's or our planning authority. The decision to install an on-site generation facility, although undoubtedly influenced by company decisions subject to our review, is, nevertheless, one that is solely within the discretion of individual customers. Accordingly, Mr. Ferris' request will be denied.

The Commission orders:

1. Except as here modified, the findings and conclusions set forth in the Recommended Decision of Administrative Law Judge John T. Vernieu are adopted as the Commission's decision.

2. Except as here granted, all exceptions to the Recommended Decision and any pending motions are denied.

3. Consolidated Edison Company of New York, Inc. (the company) shall, within sixty days of the issuance of this Opinion and Order, file rates, charges, rules and regulations for electric energy and capacity provided to, and purchased from, electric customers with qualifying on-site generation facilities that are consistent with this Opinion and Order. The company shall serve copies of its filing on those parties listing appearances in this proceeding who filed briefs or reply briefs on exceptions. Any comments on the company's filing shall, within thirty days

[148] Assemblyman Ferris Brief on Exceptions, p. 6.

of the service of that filing, be served on all parties served with that filing; and ten copies of those comments shall, within thirty days of the service of that filing, be filed with the Secretary of the Public Service Commission, Three Empire State Plaza, Albany, New York 12223. The rates, charges, rules and regulations specified in the filing will not become effective until approved by the Commission.

4. Except as specified in Paragraph 3, each electric utility shall, within sixty days of the issuance of this Opinion and Order, submit proposed rates, charges, rules and regulations for the purchase of electric energy and capacity from customers with qualifying on-site generation facilities that are consistent with this Opinion and Order. Each electric utility shall also submit proposed amendments to its tariff to remove any prohibitions from selling firm electric energy and capacity on a nondiscriminatory basis to such customers. Twenty copies of each utility's submission shall be filed with the Secretary of the Public Service Commission. Copies of each utility's submission will be served by the Secretary upon parties interested in that utility's rates, charges, rules and regulations for service to electric customers with qualifying on-site generation facilities. Any comments on a utility's submission shall, within thirty days of the service of that submission, be served on all parties served with that submission; and ten copies of those comments shall, within thirty days of the service of that submission, be filed with the Secretary of the Public Service Commission. The rates, charges, rules and regulations specified in each utility's submission will not become effective until approved by the Commission.

5. Except as specified in Paragraph 3, each electric utility shall, on the earlier of the date of its next major electric rate filing or within six months of the issuance of this Opinion and Order (but no sooner than within ninety days of

the issuance of this Opinion and Order), submit proposed rates, charges, rules and regulations for the sale of back-up, supplementary and interruptible electric energy and capacity to customers with qualifying on-site generation facilities that are consistent with this Opinion and Order. As specified in Paragraph 4, each utility's submission shall be filed with the Secretary of the Public Service Commission; copies of each utility's submission will be served upon interested parties; and comments on each utility's submission shall be served upon all parties and the Secretary of the Public Service Commission. The rates, charges, rules and regulations specified in each utility's submission will not become effective until approved by the Commission.

6. This proceeding is continued.

By the Commission,

(SIGNED) SAMUEL R. MADISON
Secretary

STATE OF NEW YORK

PUBLIC SERVICE COMMISSION

CASE 27574—CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.— On-Site Generation

HAROLD A. JERRY, JR., Commissioner, dissenting:

I dissent.

The majority is trying to eat its environmental cake and have it too.

On the one hand, the majority professes to be bound by SEQRA to weigh the environmental effects of its acts. Thus it finds that the potential environmental benefits of on-site generation outweigh the potential costs.

On the other hand, the majority admits that there will be increases in nitrogen oxide emissions, but it makes no effort to quantify or appraise such increases because it maintains that it has no authority to regulate such increases.

By this verbal legerdemain, the majority effectively repeals SEQRA.

I disagree with both of the majority's contradictory conclusions.

As the Distric of Columbia Court of Appeals stated in the recent *American Electric Power* case, the possibility exists that setting the rates at too high a level may hurt both the electric consumers of the electric utility and the public interest. The court pointed out that this may occur where the utility is subject to higher pollution control standards than are cogenerators. Thus, the court indicated that environmental concerns could justify a lower than "full avoided cost" rate even if such a rate might discourage some cogeneration projects.

Consistent with that holding and with SEQRA, I believe the Commission had an obligation to find that the environmental *costs* of a full avoided cost rate outweigh the *benefits*. Since the majority has made no effort to substantiate their bold finding to the contrary, it is not possible to point out the errors in its assessment.

I also am not willing to take any action that will result in an increase in nitrogen oxide emissions. Nitrogen oxides are, of course, one of the indispensable elements of acid rain. Thus a finding that the increased emissions may not violate ambient air quality standards is essentially irrelevant.

The majority states that the environmental aspect of increased diesel generation is the responsibility of various federal, state and city agencies and that we are not permitted by statute to consider such environmental factors. This, as I have explained, is contrary to the *American Electric Power* holding. Further, at the present time, those federal, state and city agencies have not established a regulatory framework covering nitrogen oxide emissions by diesel generation in New York City. Until such a framework is in place, I am not willing to establish a rate structure that will permit such on-site diesel generation.

Appendix E—Notice of Appeal to the Supreme Court of the United States, December 19, 1984

COURT OF APPEALS

STATE OF NEW YORK

IN THE MATTER

OF

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,
Respondent,

v.

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,

Appellant,

OCCIDENTAL CHEMICAL CORPORATION,

Intervenor,

and THE BROOKLYN UNION GAS COMPANY,

Intervernor-Respondent.

No. 438
Albany County Clerk's Index No. 12029-82

PLEASE TAKE NOTICE that Consolidated Edison Company of New York, Inc., the Respondent above-named, appeals to the Supreme Court of the United States from so much of the final judgment of the Court of Appeals of the State of New York, dated October 25, 1984, as modified the order of the Appellate Division of the Supreme Court of the State of New York, Third Judicial Department, entered on January 6, 1984.

This appeal is taken pursuant to 28 U.S.C. § 1257(2).

Dated: December 19, 1984

Very truly yours,

JOY TANNIAN
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CELESTE A. CONTRUCCI

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Hon. Guy D. Paquin
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County Clerk
Dec 19 11:58 a.m. '84
Albany, N.Y.

Received
Dec 21 1984
Court of Appeals

Affidavit of Service

COURT OF APPEALS

STATE OF NEW YORK

IN THE MATTER

OF

CONSOLIDATED EDISON COMPANY OF NEW YORK, INC.,
Respondent,

v.

PUBLIC SERVICE COMMISSION OF THE STATE OF NEW YORK,
Appellant,

OCCIDENTAL CHEMICAL CORPORATION,
Intervenor,

and THE BROOKLYN UNION GAS COMPANY,
Intervenor-Respondent.

State of New York,
County of New York, ss.:

CELESTE A. CONTRUCCI, being duly sworn, deposes and says that she is over the age of eighteen years; and that on the 19th day of December, 1984, she served Respondent's Notice of Appeal by depositing the same, enclosed in post-paid properly addressed wrappers, in an official depository maintained by the United States Postal Service, to the following, at the addresses hereinafter set forth: David E. Blabey, Esq., Counsel to the Public Service Commission of the State of New York, Three Empire

State Plaza, Albany, New York, 12223; Cullen & Dykman, attorneys for the Brooklyn Union Gas Company, 177 Montague Street, Brooklyn, New York 11201; Whiteman Osterman & Hanna, 99 Washington Avenue, Albany, New York 12260; and Sutherland, Asbill & Brennan, 1666 K Street N.W., Suite 800, Washington, D.C. 20006-2803, attorneys for Occidental Chemical Corporation.

/s/CELESTE CONTRUCCI

Sworn to before me this
19th day of December 1984.
/s/PHYLLIS MINACAPILLI
Notary Public
PHYLLIS MINACAPILLI
Notary Public, State of New York
No. 24-4692143
Qualified in Kings County
Commission Expires March 30, 1985

Appendix F—Constitutional and Statutory Provisions Involved

1. The Constitution of the United States provides in pertinent part:

Article VI:

This Constitution, and the laws of the United States which shall be made in pursuance thereof * * * shall be the supreme law of the land * * *.

2. The Public Utility Regulatory Policies Act of 1978 (PURPA), Pub. L. No. 95-617, 92 Stat. 3117 *et seq.*, provides in pertinent part:

a. Pertinent provisions of PURPA Section 201, 16 U.S.C. §796(17), (18) (1982):

(17)(A) "small power production facility" means a facility which—

(i) produces electric energy solely by the use, as a primary energy source, of biomass, waste, renewable resources, geothermal resources, or any combination thereof; and

(ii) has a power production capacity which, together with any other facilities located at the same site (as determined by the Commission), is not greater than 80 megawatts;

(B) "primary energy source" means the fuel or fuels used for the generation of electric energy, except that such term does not include, as determined under rules prescribed by the Commission, in consultation with the Secretary of Energy—

(i) the minimum amounts of fuel required for ignition, startup, testing, flame stabilization, and control uses, and

(ii) the minimum amounts of fuel required to alleviate or prevent—

(I) unanticipated equipment outages, and

(II) emergencies, directly affecting the public health, safety, or welfare, which would result from electric power outages;

(C) "qualifying small power production facility" means a small power production facility—

(i) which the Commission determines, by rule, meets such requirements (including requirements respecting fuel use, fuel efficiency, and reliablity) as the Commission may, by rule, prescribe; and

(ii) which is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

(D) "qualifying small power producer" means the owner or operator of a qualifying small power production facility;

(18) (A) "cogeneration facility" means a facility which produces—

(i) electric energy, and

(ii) steam or forms of useful energy (such as heat), which are used for industrial, commercial, heating, or cooling purposes;

(B) "qualifying cogeneration facility" means a cogeneration facility which—

(i) the Commission determines, by rule, meets such requirements (including requirements respecting minimum size, fuel use, and fuel efficiency) as the Commission may, by rule, prescribe; and

(ii) is owned by a person not primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities);

(C) "qualifying cogenerator" means the owner or operator of a qualifying cogeneration facility;

b. PURPA Section 210, 16 U.S.C. §824a-3 (1982):

(a) Cogeneration and small power production rules

Not later than 1 year after November 9, 1978, the Commission shall prescribe, and from time to time thereafter revise, such rules as it determines necessary to encourage cogeneration and small power production, and to encourage geothermal small power production facilities of not more than 80 megawatts capacity, which rules require electric utilities to offer to—

(1) sell electric energy to qualifying cogeneration facilities and qualifying small power production facilities[1] and

(2) purchase electric energy from such facilities.

Such rules shall be prescribed, after consultation with representatives of Federal and State regulatory agencies having ratemaking authority for electric utilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments. Such

[1] So in original. Probably should be followed by a comma.

rules shall include provisions respecting minimum reliability of qualifying cogeneration facilities and qualifying small power production facilities (including reliability of such facilities during emergencies) and rules respecting reliability of electric energy service to be available to such facilities from electric utilities during emergencies. Such rules may not authorize a qualifying cogeneration facility or qualifying small power production facility to make any sale for purposes other than resale.

(b) Rates for purchases by electric utilities.

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to purchase electric energy from any qualifying cogeneration facility or qualifying small power production facility, the rates for such purchase—

(1) shall be just and reasonable to the electric consumers of the electric utility and in the public interest, and

(2) shall not discriminate against qualifying cogenerators or qualifying small power producers.

No such rule prescribed under subsection (a) of this section shall provide for a rate which exceeds the incremental cost to the electric utility of alternative electric energy.

(c) Rates for sales by utilities

The rules prescribed under subsection (a) of this section shall insure that, in requiring any electric utility to offer to sell electric energy to any qualifying cogeneration facility or qualifying small power production facility, the rates for such sale—

(1) shall be just and reasonable and in the public interest, and

(2) shall not discriminate against the qualifying cogenerators or qualifying small power producers.

(d) "Incremental cost of alternative electric energy" defined

For purposes of this section, the term "incremental cost of alternative electric energy" means, with respect to electric energy purchased from a qualifying cogenerator or qualifying small power producer, the cost to the electric utility of the electric energy which, but for the purchase from such cogenerator or small power producer, such utility would generate or purchase from another source.

(e) Exemptions

(1) Not later than 1 year after November 9, 1978, and from time to time thereafter, the Commission shall, after consultation with representatives of State regulatory authorities, electric utilities, owners of cogeneration facilities and owners of small power production facilities, and after public notice and a reasonable opportunity for interested persons (including State and Federal agencies) to submit oral as well as written data, views, and arguments, prescribe rules under which geothermal small power production facilities of not more than 80 megawatts capacity, qualifying cogeneration facilities, and qualifying small power production facilities are exempted in whole or part from the Federal Power Act [16 U.S.C. 791a *et seq.*], from the Public Utility Holding Company Act [15 U.S.C. 79 *et seq.*], from State laws and regulations respecting the rates, or respecting the financial or organizational regulation, of electric utilities, or from any combination of the foregoing, if the Commission determines such exemption is necessary to encourage cogeneration and small power production.

(2) No qualifying small power production facility which has a power production capacity which, together with any

other facilities located at the same site (as determined by the Commission), exceeds 30 megawatts, or 80 megawatts for a qualifying small power production facility using geothermal energy as the primary energy source, may be exempted under rules under paragraph (1) from any provision of law or regulation referred to in paragraph (1), except that any qualifying small power production facility which produces electric energy solely by the use of biomass as a primary energy source, may be exempted by the Commission under such rules from the Public Utility Holding Company Act [15 U.S.C. 79 *et seq.*] and from State laws and regulations referred to in such paragraph (1).

(3) No qualifying small power production facility or qualifying cogeneration facility may be exempted under this subsection from—

(A) any State law or regulation in effect in a State pursuant to subsection (f) of this section,

(B) the provisions of section 210, 211, or 212 of the Federal Power Act [16 U.S.C. 824i, 824j, or 824k] or the necessary authorites for enforcement of any such provision under the Federal Power Act [16 U.S.C. 791a *et seq.*], or

(C) any license or permit requirement under part I of the Federal Power Act [16 U.S.C. 791a *et seq.*] any provision under such Act related to such a license or permit requirement, or the necessary authorities for enforcement of any such requirement.

(f) Implementation of rules for qualifying cogeneration and qualifying small power production facilities

(1) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each State regulatory authority shall, after notice and opportunity for public hearing, implement such rule (or revised rule) for each electric utility for which it has ratemaking authority.

(2) Beginning on or before the date one year after any rule is prescribed by the Commission under subsection (a) of this section or revised under such subsection, each nonregulated electric utility shall, after notice and opportunity for public hearing, implement such rule (or revised rule).

(g) Judicial review and enforcement

(1) Judicial review may be obtained respecting any proceeding conducted by State regulatory authority or nonregulated electric utility for purposes of implementing any requirement of a rule under subsection (a) of this section in the same manner, and under the same requirements, as judicial review may be obtained under section 2633 of this title in the case of a proceeding to which section 2633 of this title applies.

(2) Any person (including the Secretary) may bring an action against any electric utility, qualifying small power producer, or qualifying cogenerator to enforce any requirement established by a State regulatory authority or nonregulated electric utility pursuant to subsection (f) of this section. Any such action shall be brought only in the manner, and under the requirements, as provided under section 2633 of this title with respect to an action to which section 2633 of this title applies.

(h) Commission enforcement

(1) For purposes of enforcement of any rule prescribed by the Commission under subsection (a) of this section with respect to any operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility which are subject to the jurisdiction of the Commission under part II of the Federal Power Act [16 U.S.C. 824 *et seq.*], such rule shall be treated as a rule under the Federal Power Act [16 U.S.C. 791a *et seq.*]. Nothing in subsection (g) of this section shall apply to so much of the operations of an electric utility, a qualifying cogeneration facility or a qualifying small power production facility as are subject to the jurisdiction of the Commission under part II of the Federal Power Act.

(2)(A) The Commission may enforce the requirements of subsection (f) of this section against any State regulatory authority or nonregulated electric utility. For purposes of any such enforcement, the requirements of subsection (f)(1) of this section shall be treated as a rule enforceable under the Federal Power Act [16 U.S.C. 791a *et seq.*]. For purposes of any such action, a State regulatory authority or nonregulated electric utility shall be treated as a person within the meaning of the Federal Power Act. No enforcement action may be brought by the Commission under this section other than—

(i) an action against the State regulatory authority or nonregulated electric utility for failure to comply with the requirements of subsection (f) of this section[2] or

(ii) an action under paragraph (1).

(B) Any electric utility, qualifying cogenerator, or qualifying small power producer may petition the Commission to enforce the requirements of subsection (f) of this section as provided in subparagraph (A) of this

[2] So in original. Probably should be followed by a comma.

paragraph. If the Commission does not initiate an enforcement action under subparagraph (A) against a State regulatory authority or nonregulated electric utility within 60 days following the date on which a petition is filed under this subparagraph with respect to such authority, the petitioner may bring an action in the appropriate United States district court to require such State regulatory authority or nonregulated electric utility to comply with such requirements, and such court may issue such injunctive or other relief as may be appropriate. The Commission may intervene as a matter of right in any such action.

(i) Federal contracts

No contract between a Federal agency and any electric utility for the sale of electric energy by such Federal agency for resale which is entered into after November 9, 1978, may contain any provision which will have the effect of preventing the implementation of any rule under this section with respect to such utility. Any provision in any such contract which has such effect shall be null and void.

(j) Definitions

For purposes of this section, the terms "small power production facility", "qualifying small power production facility", "qualifying small power producer", "primary energy source", "cogeneration facility", "qualifying cogeneration facility", and "qualifying cogenerator" have the respective meanings provided for such terms under section 3(17) and (18) of the Federal Power Act [16 U.S.C. 796(17), (18)].

3. The Federal Energy Regulatory Commission's regulations under Sections 201 and 210 of the Public Utility Regulatory Policies Act of 1978, 18 C.F.R. Part 292 (1984), provide in pertinent part:

Subpart A—General Provisions

§292.101 Definitions

(a) *General rule.* Terms defined in the Public Utility Regulatory Policies Act of 1978 (PURPA) shall have the same meaning for purposes of this part as they have under PURPA, unless further defined in this part.

(b) *Definitions.* The following definitions apply for purposes of this part.

(1) "Qualifying facility" means a cogeneration facility or a small power production facility which is a qualifying facility under Subpart B of this part of the Commission's regulations.

(2) "Purchase" means the purchase of electric energy or capacity or both from a qualifying facility by an electric utility.

(3) "Sale" means the sale of electric energy or capacity or both by an electric utility to a qualifying facility.

(4) "System emergency" means a condition on a utility's system which is likely to result in imminent significant disruption of service to customers or is imminently likely to endanger life or property.

(5) "Rate" means any price, rate, charge, or classification made, demanded, observed or received with respect to the sale or purchase of electric energy or capacity, or any rule, regulation, or practice respecting any such rate, charge, or classification, and any contract pertaining to the sale or purchase of electric energy or capacity.

(6) "Avoided costs" means the incremental costs to an electric utility of electric energy or capacity or both which,

but for the purchase from the qualifying facility or qualifying facilities, such utility would generate itself or purchase from another source.

(7) "Interconnection costs" means the reasonable costs of connection, switching, metering, transmission, distribution, safety provisions and administrative costs incurred by the electric utility directly related to the installation and maintenance of the physical facilities necessary to permit interconnected operations with a qualifying facility, to the extend such costs are in excess of the corresponding costs which the electric utility would have incurred if it had not engaged in interconnected operations, but instead generated an equivalent amount of electric energy itself or purchased an equivalent amount of electric energy or capacity from other sources. Interconnection costs do not include any costs included in the calculation of avoided costs.

(8) "Supplementary power" means electric energy or capacity supplied by an electric utility, regularly used by a qualifying facility in addition to that which the facility generates itself.

(9) "Back-up power" means electric energy or capacity supplied by an electric utility to replace energy ordinarily generated by a facility's own generation equipment during an unscheduled outage of the facility.

(10) "Interruptible power" means electric energy or capacity supplied by an electric utility subject to interruption by the electric utility under specified conditions.

(11) "Maintenance power" means electric energy or capacity supplied by an electric utility during scheduled outages of the qualifying facility.

Suppart B—Qualifying Cogeneration and Small Power Production Facilities

§292.201 Scope.

This subpart applies to the criteria for and manner of becoming a qualifying small power production facility and a qualifying cogeneration facility under sections 3(17)(C) and 3(18)(B), respectively, of the Federal Power Act, as amended by section 201 of the Public Utility Regulatory Policies Act of 1978 (PURPA).

§292.202 Definitions.

For purposes of this subpart:

(a) "Biomass" means any organic material not derived from fossil fuels;

(b) "Waste" means by-product materials other than biomass;

(c) "Cogeneration facility" means equipment used to produce electric energy and forms of useful thermal energy (such as heat or steam), used for industrial, commercial, heating, or cooling purposes, through the sequential use of energy;

(d) "Topping-cycle cogeneration facility" means a cogeneration facility in which the energy input to the facility is first used to produce useful power output, and the reject heat from power production is then used to provide useful thermal energy;

(e) "Bottoming-cycle cogeneration facility" means a cogeneration facility in which the energy input to the system is first applied to a useful thermal energy process, and the reject heat emerging from the process is then used for power production;

(f) "Supplementary firing" means an energy input to the cogeneration facility used only in the thermal process of a topping-cycle cogeneration facility, or only in the electric generating process of a bottoming-cycle cogeneration facility;

(g) "Useful power output" of a cogeneration facility means the electric or mechanical energy made available for use, exclusive of any such energy used in the power production process;

(h) "Useful thermal energy output" of a topping-cycle cogeneration facility means the thermal energy made available for use in any industrial or commercial process, or used in any heating or cooling application;

(i) "Total energy output" of a topping-cycle cogeneration facility is the sum of the useful power output and useful thermal energy output;

(j) "Total energy input" means the total energy of all forms supplied from external sources;

(k) "Natural gas" means either natural gas unmixed, or any mixture of natural gas and artificial gas;

(l) "Oil" means crude oil, residual fuel oil, natural gas liquids, or any refined petroleum products; and

(m) Energy input in the case of energy in the form of natural gas or oil is to be measured by the lower heating value of the natural gas or oil.

(n) "Electric utility holding company" means a holding company, as defined in section 2(a)(7) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(7) which owns one or more electric utilities, as defined in section 2(a)(3) of that Act, 15 U.S.C. 79b(a)(3), but does not include any holding company which is exempt by rule or order adopted or issued pursuant to sections 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79c(a)(3) or 79c(a)(5).

(o) "Utility geothermal small power production facility" means a small power production facility which uses geothermal energy as the primary energy resource and of which more than 50 percent is owned either:

(1) By an electric utility or utilities, electric utility holding company or companies, or any combination thereof.

(2) By any company 50 percent or more of the outstanding voting securities of which of which [*sic*] are directly or indirectly owned, controlled, or held with power to vote by an electric utility, electric utility holding company, or any combination thereof.

§292.203 General requirements for qualification.

(a) *Small power production facilities.* A small power production facility is a qualifying facility if it:

(1) Meets the maximum size criteria specified in §292.204(a);

(2) Meets the fuel use criteria specified in §292.204(b); and

(3) Meets the ownership criteria specified in §292.206.

(b) *Cogeneration facilities.* (1) A cogeneration facility, including any diesel and dual-fuel cogeneration facility, is a qualifying facility if it:

(i) Meets any applicable operating and efficiency standards specified in §292.205(a) and (b); and

(ii) Meets the ownership criteria specified in §292.206.

(2) For purposes of qualification of a cogeneration facility for exemption from incremental pricing, a cogeneration facility must qualify under §292.205(c).

§292.204 Criteria for qualifying small power production facilities.

(a) *Size of the facility*—(1) *Maximum size.* The power production capacity of the facility for which qualification is sought, together with the capacity of any other facilities which use the same energy resource, are owned by the same person, and are located at the same site, may not exceed 80 megawatts.

(2) *Method of calculation.* (i) For purposes of this paragraph, facilities are considered to be located at the same site as the facility for which qualification is sought if they are located within one mile of the facility for which qualification is sought and, for hydroelectric facilities, if they use water from the same impoundment for power generation.

(ii) For purposes of making the determination in clause (i), the distance between facilities shall be measured from the electrical generating equipment of a facility.

(3) *Waiver.* The Commission may modify the application of paragraph (a)(2) of this section, for good cause.

(b) *Fuel use.* (1) (i) The primary energy source of the facility must be biomass, waste, renewable resources, geothermal resources, or any combination thereof, and 75 percent or more of the total energy input must be from these sources.

(ii) Any primary energy source which, on the basis of its energy content, is 50 percent or more biomass shall be considered biomass.

(2) Use of oil, natural gas, and coal by a facility may not, in the aggregate, exceed 25 percent of the total energy input of the facility during any calendar year period.

§292.205 Criteria for qualifying cogeneration facilities.

(a) *Operating and efficiency standards for topping-cycle facilities*—(1) *Operating standard.* For any topping-cycle cogeneration facility, the useful thermal energy output of the facility must, during any calendar year period, be no less than 5 percent of the total energy output.

(2) *Efficiency standard.* (i) For any topping-cycle cogeneration facility for which any of the energy input is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility plus one-half the useful thermal energy output, during any calendar year period, must:

(A) Subject to paragraph (a)(2)(i)(B) of this section be no less than 42.5 percent of the total energy input of natural gas and oil to the facility; or

(B) If the useful thermal energy output is less than 15 percent of the total energy output of the facility, be no less than 45 percent of the total energy input of natural gas and oil to the facility.

(ii) For any topping-cycle cogeneration facility not subject to paragraph (a)(2)(i) of this section there is no efficiency standard.

(b) *Efficiency standards for bottoming-cycle facilities.*

(1) For any bottoming-cycle cogeneration facility for which any of the energy input as supplementary firing is natural gas or oil, and the installation of which began on or after March 13, 1980, the useful power output of the facility must, during any calendar year period, be no less than 45 percent of the energy input of natural gas and oil for supplementary firing.

(2) For any bottoming-cycle cogeneration facility not covered by paragraph (b)(1) of this section, there is no efficiency standard.

(c) *Exemption from incremental pricing.* (1) Natural gas used in any topping-cycle cogeneration facility is eligible for an exemption from incremental pricing under Title II of the Natural Gas Policy Act of 1978 (NGPA) and Part 282 of the Commission's rules if:

(i) The facility meets the operating and efficiency standards under paragraphs (a)(1) and (2)(i) of this section and is a qualifying facility under §292.203(b)(1); or

(ii) The facility is a qualifying facility under Subpart E of this part.

(2) Natural gas used in any bottoming-cycle cogeneration facility, not subject to an exemption from incremental pricing under Subpart E of this part, is eligible for an exemption under Title II of the NGPA and Part 282 of the Commission's rules to the extent that reject heat emerging from the useful thermal energy process is made available for use for power production.

(3) Nothing in this subpart affects any exemption provided under Subpart E of this part.

(4) Natural gas used for supplementary firing in any cogeneration facility is not eligible under this part for exemption from incremental pricing.

(d) *Waiver.* The Commission may waive any of the requirements of paragraphs (a), (b) and (c) of this section upon a showing that the facility will produce significant energy savings.

§292.206 Ownership criteria.

(a) *General rule.* A cogeneration facility or small power production facility may not be owned by a person primarily engaged in the generation or sale of electric power (other than electric power solely from cogeneration facilities or small power production facilities).

(b) *Ownership test.* For purposes of this section, a cogeneration or small power production facility shall be considered to be owned by a person primarily engaged in the generation or sale of electric power, if more than 50 percent of the equity interest in the facility is held by an electric utility or utilities, or by an electric utility holding company, or companies, or any combination thereof. If a wholly or partially owned subsidiary of an electric utility or electric utility holding company has an ownership interest of a facility, the subsidiary's ownership interest shall be considered as ownership by an electric utility or electric utility holding company.

(c) *Exceptions.* For purposes of this section a company shall not be considered to be an "electric utility" company if it:

(1) Is a subsidiary of an electric utility holding company which is exempt by rule or order adopted or issued pursuant to section 3(a)(3) or 3(a)(5) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79c(a)(3), 79c(a)(5); or

(2) Is declared not to be an electric utility company by rule or order of the Securities and Exchange Commission pursuant to section 2(a)(3)(A) of the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3)(A).

§292.207 Procedures for obtaining qualifying status.

(a) *Qualification.* (1) A small power production facility or cogeneration facility which meets the criteria for qualification set forth in §292.203 is a qualifying facility.

(2) The owner or operator of any facility qualifying under this paragraph shall furnish notice to the Commission providing the information set forth in paragraphs (b)(2) (i) through (iv) of this section.

(b) *Optional procedure*—(1) *Application for Commission certification.* Pursuant to the provisions of this paragraph, the owner or operator of the facility may file with this Commission an application for Commission certification that the facility is a qualifying facility.

(2) *General contents of application.* The application shall contain the following information:

(i) The name and address of the applicant and location of the facility;

(ii) A brief description of the facility, including a statement indicating whether such facility is a small power production facility or a cogeneration facility;

(iii)The primary energy source used or to be used by the facility;

(iv) The power production capacity of the facility; and

(v) The percentage of ownership by any electric utility or by any electric utility holding company, or by any person owned by either.

(3) *Additional application requirements for small power production facilities.* An application by a small power producer for Commission certification shall contain the following additional information:

(i) The location of the facility in relation to any other small power production facilities located within one mile of the facility, owned by the applicant which use the same energy source; and

(ii) Information identifying any planned usage of natural gas, oil or coal.

(4) *Additional application requirements for cogeneration facilities.* An application by a cogenerator for Commission certification shall contain the following additional information:

(i) A description of the cogeneration system, including whether the facility is a topping or bottoming cycle and sufficient information to determine that any applicable requirements under §292.205 will be met; and

(ii)The date installation of the facility began or will begin.

(5) *Commission action.* Within 90 days of the filing of an application, the Commission shall issue an order granting or denying the application, tolling the time for issuance of an order, or setting the matter for hearing. Any order denying certification shall identify the specific requirements which were not met. If no order is issued within 90 days of the filing of the complete application, it shall be deemed to have been granted.

(6) *Notice.* (i) Applications for certification filed under this paragraph shall include a copy of a notice of the request for certification for publication in the Federal Register. The notice shall state the applicant's name, the date of the application, and a brief description of the facility for which qualification is sought. This description shall include:

(A) A statement indicating whether such facility is a small power production facility or a cogeneration facility;

(B) The primary energy source used or to be used by the facility;

(C) The power production capacity of the facility; and

(D) The location of the facility.

(ii) The notice shall be in the following form:

(Name of Applicant)
Docket No. QF—.

NOTICE OF APPLICATION FOR COMMISSION CERTIFICATION OF QUALIFYING STATUS OF A (SMALL POWER PRODUCTION) (COGENERATION) FACILITY

On (date application was filed), (name and address of applicant) filed with the Federal Energy Regulatory Com-

mission an application to be certified as a qualifying (small power production) (cogeneration) facility pursuant to §292.207 of the Commission's rules.

(Brief description of the facility).

Any person desiring to be heard or objecting to the granting of qualifying status should file a petition to intervene or protest with the Federal Energy Regulatory Commission, 825 North Capitol Street, N.E., Washington, D.C. 20426, in accordance with §§385.209 and 385.214 of this chapter. All such petitions or protests must be filed within 30 days after the date of publication of this notice and must be served on the applicant. Protests will be considered by the Commission in determining the appropriate action to be taken but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a petition to intervene. Copies of this filing are on file with the Commission and are available for public inspection.

(c) *Notice requirements for facilities of 500 kW or more.* An electric utility is not required to purchase electric energy from a facility with a design capacity of 500 kW or more until 90 days after the facility notifies the utility that it is a qualifying facility, or 90 days after the facility has applied to the Commission under paragraph (b) of this section.

(d) *Revocation of qualifying status.* (1) The Commission may revoke the qualifying status of a qualifying facility which has been certified under this section if such facility fails to comply with any of the statements contained in its application for Commission certification.

(2) Prior to undertaking any substantial alteration or modification of a qualifying facility which has been certified under this section, a small power producer or cogenerator may apply to the Commission for a determination that the proposed alteration or modification will not result in a revocation of qualifying status.

Subpart C—Arrangements Between Electric Utilities and Qualifying Cogeneration and Small Power Production Facilities Under Section 210 of the Public Utility Regulatory Policies Act of 1978

§292.301 Scope

(a) *Applicability.* This subpart applies to the regulation of sales and purchases between qualifying facilities and electric utilities.

(b) *Negotiated rates or terms.* Nothing in this subpart:

(1) Limits the authority of any electric utility or any qualifying facility to agree to a rate for any purchase, or terms or conditions relating to any purchase, which differ from the rate or terms or conditions which would otherwise be required by this subpart; or

(2) Affects the validity of any contract entered into between a qualifying facility and an electric utility for any purchase.

§292.302 Availability of electric utility system cost data.

(a) *Applicability.* (1) Except as provided in paragraph (a) (2) of this section, paragraph (b) applies to each electric utility, in any calendar year, if the total sales of electric energy by such utility for purposes other than resale ex-

ceeded 500 million kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding calendar year.

(2) Each utility having total sales of electric energy for purposes other than resale of less than one billion kilowatt-hours during any calendar year beginning after December 31, 1975, and before the immediately preceding year, shall not be subject to the provisions of this section until June 30, 1982.

(b) *General rule.* To make available data from which avoided costs may be derived, not later than November 1, 1980, June 30, 1982, and not less often than every two years thereafter, each regulated electric utility described in paragraph (a) of this section shall provide to its State regulatory authority, and shall maintain for public inspection, and each nonregulated electric utility described in paragraph (a) of this section shall maintain for public inspection, the following data:

(1) The estimated avoided cost on the electric utility's system, solely with respect to the energy component, for various levels of purchases from qualifying facilities. Such levels of purchases shall be stated in blocks of not more than 100 megawatts for systems with peak demand of 1000 megawatts or more, and in blocks equivalent to not more than 10 percent of the system peak demand for systems of less than 1000 megawatts. The avoided costs shall be stated on a cents per kilowatt-hour basis, during daily and seasonal peak and off-peak periods, by year, for the current calendar year and each of the next 5 years;

(2) The electric utility's plan for the addition of capacity by amount and type, for purchases of firm energy and capacity, and for capacity retirements for each year during the succeeding 10 years; and

(3) The estimated capacity costs at completion of the planned capacity additions and planned capacity firm purchases, on the basis of dollars per kilowatt, and the associated energy costs of each unit, expressed in cents per kilowatt hour. These costs shall be expressed in terms of individual generating units and of individual planned firm purchases.

(c) *Special rule for small electric utilites.* (1) Each electric utility (other than any electric utility to which paragraph (b) of this section applies) shall, upon request:

(i) Provide comparable data to that required under paragraph (b) of this section to enable qualifying facilities to estimate the electric utility's avoided costs for periods described in paragraph (b) of this section; or

(ii) With regard to an electric utility which is legally obligated to obtain all its requirements for electric energy and capacity from another electric utility, provide the data of its supplying utility and the rates at which it currently purchases such energy and capacity.

(2) If any such electric utility fails to provide such information on request, the qualifying facility may apply to the State regulatory authority (which has ratemaking authority over the electric utility) or the Commission for an order requiring that the information be provided.

(d) *Substitution of alternative method.* (1) After public notice in the area served by the electric utility, and after opportunity for public comment, any State regulatory authority may require (with respect to any electric utility over which it has ratemaking authority), or any nonregulated electric utility may provide, data different than those which are otherwise required by this section if it determines that avoided costs can be derived from such data.

(2) Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated utility which requires such different data shall notify the Commission within 30 days of making such determination.

(e) *State Review.* (1) Any data submitted by an electric utility under this section shall be subject to review by the State regulatory authority which has ratemaking authority over such electric utility.

(2) In any such review, the electric utility has the burden of coming forward with justification for its data.

§292.303 Electric utility obligations under this subpart.

(a) *Obligation to purchase from qualifying facilities.* Each electric utility shall purchase, in accordance with § 292.304, any energy and capacity which is made available from a qualifying facility:

(1) Directly to the electric utility; or

(2) Indirectly to the electric utility in accordance with paragraph (d) of this section.

(b) *Obligation to sell to qualifying facilities.* Each electric utility shall sell to any qualifying facility, in accordance with § 292.305, any energy and capacity requested by the qualifying facility.

(c) *Obligation to interconnect.* (1) Subject to paragraph (c) (2) of this section, any electric utility shall make such interconnections with any qualifying facility as may be necessary to accomplish purchases or sales under this subpart. The obligation to pay for any interconnection costs shall be determined in accordance with § 292.306.

(2) No electric utility is required to interconnect with any qualifying facility if, solely by reason of purchases or sales over the interconnection, the electric utility would become subject to regulation as a public utility under Part II of the Federal Power Act.

(d) *Transmission to other electric utilities.* If a qualifying facility agrees, an electric utility which would otherwise be obligated to purchase energy or capacity from such qualifying facility may transmit the energy or capacity to any other electric utility. Any electric utility to which such energy or capacity is transmitted shall purchase such energy or capacity under this subpart as if the qualifying facility were supplying energy or capacity directly to such electric utility. The rate for purchase by the electric utility to which such energy is transmitted shall be adjusted up or down to reflect line losses pursuant to § 292.304 (e) (4) and shall not include any charges for transmission.

(e) *Parallel operation.* Each electric utility shall offer to operate in parallel with a qualifying facility, provided that the qualifying facility complies with any applicable standards established in accordance with § 292.308.

§ 292.304 Rates for purchases.

(a) *Rates for purchases.* (1) Rates for purchases shall:

(i) Be just and reasonable to the electric consumer of the electric utility and in the public interest; and

(ii) Not discriminate against qualifying cogeneration and small power production facilities.

(2) Nothing in this subpart requires any electric utility to pay more than the avoided costs for purchases.

(b) *Relationship to avoided costs.* (1) For purposes of this paragraph, "new capacity" means any purchase from capacity of a qualifying facility, construction of which was commenced on or after November 9, 1978.

(2) Subject to paragraph (b) (3) of this section, a rate for purchases satisfies the requirements of paragraph (a) of this section if the rate equals the avoided costs determined after consideration of the factors set forth in paragraph (e) of this section.

(3) A rate for purchses (other than from new capacity) may be less than the avoided cost if the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or the nonregulated electric utility determines that a lower rate is consistent with paragraph (a) of this section, and is sufficient to encourage cogeneration and small power production.

(4) Rates for purchases from new capacity shall be in accordance with paragraph (b) (2) of this section, regardless of whether the electric utility making such purchases is simultaneously making sales to the qualifying facility.

(5) In the case in which the rates for purchases are based upon estimates of avoided costs over the specific term of the contract or other legally enforceable obligation, the rates for such purchases do not violate this subpart if the rates for such purchases differ from avoided costs at the time of delivery.

(c) *Standard rates for purchases.* (1) There shall be put into effect (with respect to each electric utility) standard rates for purchases from qualifying facilities with a design capacity of 100 kilowatts or less.

(2) There may be put into effect standard rates for purchases from qualifying facilities with a design capacity of more than 100 kilowatts.

(3) The standard rates for purchases under this paragraph:

(i) Shall be consistent with paragraphs (a) and (e) of this section; and

(ii) May differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies.

(d) *Purchases "as available" or pursuant to a legally enforceable obligation.* Each qualifying facility shall have the option either:

(1) To provide energy as the qualifying facility determines such energy to be available for such purchases, in which case the rates for such purchases shall be based on the purchasing utility's avoided costs calculated at the time of delivery; or

(2) To provide energy or capacity pursuant to a legally enforceable obligation for the delivery of energy or capacity over a specified term, in which case the rates for such purchases shall, at the option of the qualifying facility exercised prior to the beginning of the specified term, be based on either:

(i) The avoided costs calculated at the time of delivery; or

(ii) The avoided costs calculated at the time the obligation is incurred.

(e) *Factors affecting rates for purchases.* In determining avoided costs, the following factors shall, to the extent practicable, be taken into account:

(1) The data provided pursuant to § 292.302 (b), (c), or (d), including State review of any such data;

(2) The availability of capacity or energy from a qualifying facility during the system daily and seasonal peak periods, including:

(i) The ability of the utility to dispatch the qualifying facility;

(ii) The expected or demonstrated reliability of the qualifying facility;

(iii) The terms of any contract or other legally enforceable obligation, including the duration of the obligation, termination notice requirement and sanctions for non-compliance;

(iv) The extent to which scheduled outages of the qualifying facility can be usefully coordinated with scheduled outages of the utility's facilities;

(v) The usefulness of energy and capacity supplied from a qualifying facility during system emergencies, including its ability to separate its load from its generation;

(vi) The individual and aggregate value of energy and capacity from qualifying facilities on the electric utility's system; and

(vii) The smaller capacity increments and the shorter lead times available with additions of capacity from qualifying facilities; and

(3) The relationship of the availability of energy or capacity from the qualifying facility as derived in paragraph (e) (2) of this section, to the ability of the electric utility to avoid costs, including the deferral of capacity additions and the reduction of fossil fuel use; and

(4) The costs of savings resulting from variations in line losses from those that would have existed in the absence of purchases from a qualifying facility, if the purchasing electric utility generated an equivalent amount of energy itself or purchased an equivalent amount of electric energy or capacity.

(f) *Periods during which purchases not required.*
(1) Any electric utility which gives notice pursuant to paragraph (f) (2) of this section will not be required to purchase electric energy or capacity during any period during which, due to operational circumstances, purchases from qualifying facilities will result in costs greater than those which the utility would incur if it did not make such purchases, but instead generated an equivalent amount of energy itself.

(2) Any electric utility seeking to invoke paragraph (f) (1) of this section must notify, in accordance with applicable State law or regulation, each affected qualifying facility in time for the qualifying facility to cease the delivery or energy or capacity to the electric utility.

(3) Any electric utility which fails to comply with the provisions of paragraph (f) (2) of this section will be required to pay the same rate for such purchase of energy or capacity as would be required had the period described in paragraph (f) (1) of this section not occurred.

(4) A claim by an electric utility that such a period has occurred or will occur is subject to such verification by its State regulatory authority as the State regulatory authority determines necessary or appropriate, either before or after the occurrence.

§ 292.305 Rates for sales.

(a) *General rules.* (1) Rates for sales:

(i) Shall be just and reasonable and in the public interest; and

(ii) Shall not discriminate against any qualifying facility in comparison to rates for sales to other customers served by the electric utility.

(2) Rates for sales which are based on accurate data and consistent systemwide costing principles shall not be considered to discriminate against any qualifying facility to the extent that such rates apply to the utility's other customers with similar load or other cost-related characteristics.

(b) *Additional Services to be Provided to Qualifying Facilities.* (1) Upon request of a qualifying facility, each electric utility shall provide:

(i) Supplementary power;

(ii) Back-up power;

(iii) Maintenance power; and

(iv) Interruptible power.

(2) The State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and the Commission (with respect to any nonregulated electric utility) may waive any requirement of paragraph (b) (1) of this section if, after notice in the area served by the electric utility and after opportunity for public comment, the electric utility demonstrates and the State regulatory authority or the Commission, as the case may be, finds that compliance with such requirement will:

(i) Impair the electric utility's ability to render adequate service to its customers; or

(ii) Place an undue burden on the electric utility.

(c) *Rates for sales of back-up and maintenance power.* The rate for sales of back-up power or maintenance power:

(1) Shall not be based upon an assumption (unless supported by factual data) that forced outages or other reductions in electric output by all qualifying facilities on an electric utility's system will occur simultaneously, or during the system peak, or both; and

(2) Shall take into account the extent to which scheduled outages of the qualifying facilities can be usefully coordinated with scheduled outages of the utility's facilities.

§ 292.306 Interconnection costs.

(a) *Obligation to pay.* Each qualifying facility shall be obligated to pay any interconnection costs which the State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may assess against the qualifying facility on a nondiscriminatory basis with respect to other customers with similar load characteristics.

(b) *Reimbursement of interconnection costs.* Each State regulatory authority (with respect to any electric utility over which it has ratemaking authority) and nonregulated utility shall determine the manner for payments of interconnection costs, which may include reimbursement over a reasonable period of time.

§ 292.307 System Emergencies.

(a) *Qualifying facility obligation to provide power during system emergencies.* A qualifying facility shall be required to provide energy or capacity to an electric utility during a system emergency only to the extent:

(1) Provided by agreement between such qualifying facility and electric utility; or

(2) Ordered under section 202(c) of the Federal Power Act.

(b) *Discontinuance of purchases and sales during system emergencies.* During any system emergency, an electric utility may discontinue:

(1) Purchases from a qualifying facility if such purchases would contribute to such emergency; and

(2) Sales to a qualifying facility, provided that such discontinuance is on a nondiscriminatory basis.

§ 292.308 Standards for operating reliability.

Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may establish reasonable standards to ensure system safety and reliability of interconnected operations. Such standards may be recom-

mended by any electric utility, any qualifying facility, or any other person. If any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility establishes such standards, it shall specify the need for such standards on the basis of system safety and reliability.

Subpart D—Implementation

§ 292.401 Implementation by State regulatory authorities and nonregulated electric utilities.

(a) *State regulatory authorities.* Not later than one year after these rules take effect, each State regulatory authority shall, after notice and an opportunity for public hearing, commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to resolve disputes between qualifying facilities and electric utilities arising under Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(b) *Nonregulated electric utilities.* Not later than one year after these rules take effect, each nonregulated electric utility shall, after notice and an opportunity for public hearing commence implementation of Subpart C (other than § 292.302 thereof). Such implementation may consist of the issuance of regulations, an undertaking to comply with Subpart C, or any other action reasonably designed to implement such subpart (other than § 292.302 thereof).

(c) *Reporting requirement.* Not later than one year after these rules take effect, each State regulatory authority and nonregulated electric utility shall file with the Commission a report describing the manner in which it will implement Subpart C (other than § 292.302 thereof).

§ 292.402 Implementation of certain reporting requirements.

Any electric utility which fails to comply with the requirements of § 292.302(b) shall be subject to the same penalties to which it may be subjected for failure to comply with the requirements of the Commission's regulations issued under section 133 of PURPA.

§ 292.403 Waivers.

(a) *State regulatory authority and nonregulated electric utility waivers.* Any State regulatory authority (with respect to any electric utility over which it has ratemaking authority) or nonregulated electric utility may, after public notice in the area served by the electric utility, apply for a waiver from the application of any of the requirements of Subpart C (other than § 292.302 thereof).

(b) *Commission action.* The commission will grant such a waiver only if an applicant under paragraph (a) of this section demonstrates that compliance with any of the requirements of Subpart C is not necessary to encourage cogeneration and small power production and is not otherwise required under section 210 of PURPA.

Subpart F—Exemption of Qualifying Small Power Production Facilities and Cogeneration Facilities from Certain Federal and State Laws and Regulations.

§ 292.601 Exemption to qualifying facilities from the Federal Power Act.

(a) *Applicability.* This section applies to qualifying facilities, other than those described in paragraph (b) of this section.

(b) *Exclusion.* This section does not apply to a qualifying small power production facility with a power production capacity which exceeds 30 megawatts, if such facility uses any primary energy source other than geothermal resources.

(c) *General rule.* Any qualifying facility described in paragraph (a) of this section shall be exempt from all sections of the Federal Power Act, except:

(1) Section 1-18, and 21-30;

(2) Sections 202(c), 210, 211, and 212;

(3) Sections 305(c); and

(4) Any necessary enforcement provision of Part III with regard to the sections listed in paragraphs (c)(1), (2) and (3) of this section.

§ 292.602 Exemption to qualifying facilities from the Public Utility Holding Company Act and certain State law and regulation.

(a) *Applicability.* This section applies to any qualifying facility described in § 292.601(a), and to any qualifying small power production facility with a power production capacity over 30 megawatts if such facility produces electric energy solely by the use of biomass as a primary energy source.

(b) *Exemption from the Public Utility Holding Company Act of 1935.* A qualifying facility described in paragraph (a) of this section or a utility geothermal small power production facility shall not be considered to be an "electric utility company" as defined in section 2(a)(3) of

the Public Utility Holding Company Act of 1935, 15 U.S.C. 79b(a)(3).

(c) *Exemption from certain State law and regulation.* (1) Any qualifying facility shall be exempted (except as provided in paragraph (c)(2)) of this section from State law or regulation respecting:

(i) The rates of electric utilities; and

(ii) The financial and organizational regulation of electric utilities.

(2) A qualifying facility may not be exempted from State law and regulation implementing Subpart C.

(3) Upon request of a State regulatory authority or nonregulated electric utility, the Commission may consider a limitation on the exemptions specified in paragraph (c)(1) of this section.

(4) Upon request of any person, the Commission may determine whether a qualifying facility is exempt from a particular State law or regulation.

4. The New York Public Service Law (McKinney Supp. 1984-85) provides in pertinent part:

a. Pertinent provisions of Public Service Law Section 2:

2-a. The term "co-generation facility", when used in this chapter, includes any facility with an electric generating capacity of up to eighty megawatts, together with any related facilities located at the same project site, which is fueled by coal, gas, wood, alcohol, solid waste refuse-derived fuel, water or oil, to the extent any such oil fueled facility was fueled by oil prior to the effective date

of this subdivision and there is no increase in the amount of oil used at the facility or to the extent oil is used as a backup fuel for such facility, and which simultaneously or sequentially produces either electricity or shaft horsepower and useful thermal energy which is used solely for industrial and/or commercial purposes.

2-b. The term "alternate energy production facility", when used in this chapter, includes any solar, wind turbine, waste management resource recovery, refuse-derived fuel or wood burning facility, together with any related facilities located at the same project site, with an electric generating capacity of up to eighty megawatts, which produces electricty, gas or useful thermal energy.

2-c. The term "small hydro facility", when used in this chapter, includes any hydroelectric facility, together with any related facilities located at the same project site, with an electric generating capacity of up to eighty megawatts.

b. Public Service Law Section 66-c (1) provides:

It is hereby declared to be the policy of this state that it is in the public interest to encourage the development of alternate energy production facilities, co-generation facilities and small hydro facilities in order to conserve our finite and expensive energy resources and to provide for their most efficient utilization. In furtherance of this declared policy, the commission shall encourage the participation of utilities in co-generation, small hydro and alternate energy production facilities either directly or through subsidiaries formed pursuant to the provisions of subdivision two of this section. In addition, the commission shall require any electric corporation or steam corporation (a) to enter into long-term contracts to purchase or

wheel electricity or useful thermal energy from any alternate energy production, small hydro or co-generation facility under such terms and conditions as the commission shall find just and economically reasonable to the corporation's ratepayers, non-discriminatory to co-generators, small hydro producers and alternate energy producers and further the public policy set forth herein; provided, however, the commission shall establish a minimum sales price for such purchased electricity from any such facility developed on or after June twenty-six, nineteen hundred eighty, of at least six cents per kilowatt hour for each utility, which sales price shall be subject to periodic revision by the commission to reflect increases in the cost of utility generated electricity, and (b) to provide supplemental or backup power to any alternate energy production, small hydro or co-generation facility on a non-discriminatory basis and at just and reasonable rates; provided however, that nothing contained in this section shall require any such electric or steam corporation to construct any additional facilities for such purposes unless such facilities are paid for in full by the owner or operator of the co-generation, small hydro or alternate energy production facility.

5. The May 12, 1982 order of the Public Service Commission of the State of New York in Case 27574 is set forth in Appendix D hereto (pp. 157a-58a, Ordering Clause 3).